# Proposed Greater Mooses Tooth Two Development Project

## Supplemental Environmental Impact Statement for the Alpine Satellite Development Plan

**FINAL**

**Volume 3b: Appendices O-R**

# The Bureau of Land Management Today

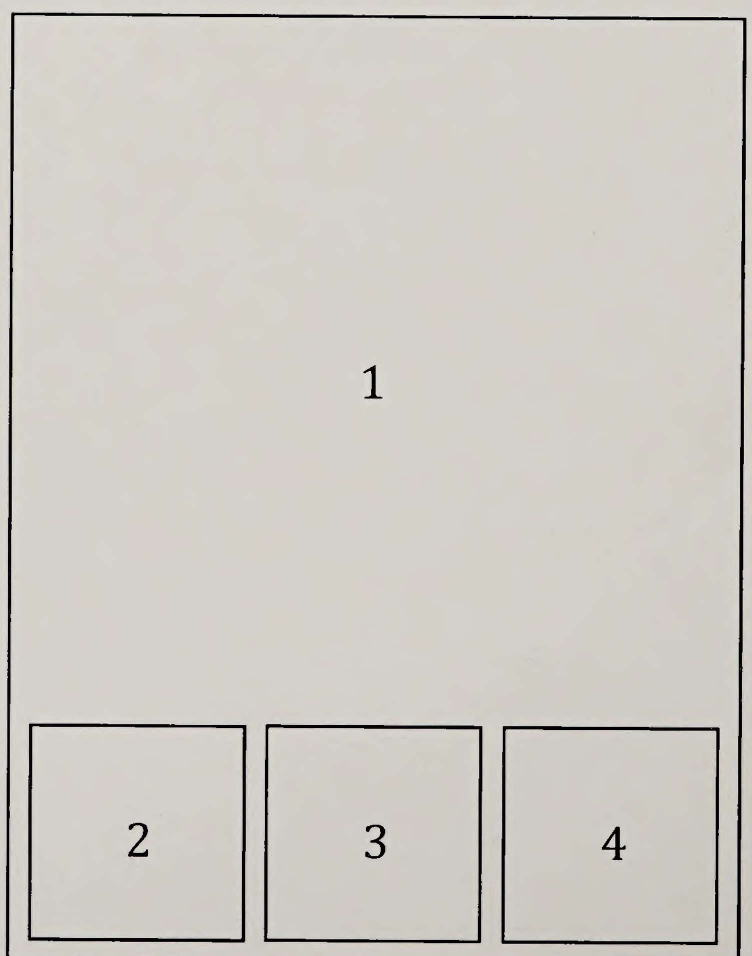
## *Our Vision*

To enhance the quality of life for all citizens through the balanced stewardship of America's public lands and resources.

## *Our Mission*

To sustain the health, diversity, and productivity of the public lands for the use and enjoyment of present and future generations.






1. **BLM Cover Photos**
2. Aerial of production pad, North Slope
© ConocoPhillips
3. Caribou, National Petroleum Reserve, Alaska
4. Crea Creek flowing into Lake L9819, National Petroleum Reserve, Alaska
5. White-fronted goose, National Petroleum Reserve, Alaska

BLM/AK/PL-18/009+1610+F0200

# Alpine Satellite Development Plan for the Proposed Greater Mooses Tooth 2 Development Project

## Final Supplemental Environmental Impact Statement

### Volume 3-b: Appendices

Prepared by:

U.S. Department of the Interior
Bureau of Land Management
Anchorage, AK

In cooperation with:

Native Village of Nuiqsut
U.S. Army Corps of Engineers
U.S. Environmental Protection Agency
U.S. DOI Fish and Wildlife Service
U.S. DOI Bureau of Ocean Energy Management
State of Alaska
North Slope Borough
Inupiat Community of the Arctic Slope

August 2018

**Total Cost of Producing the EIS: $1.1 Million.**

# Contents of Volumes 3-B



See Volume 3-A for Appendices A-N.

# APPENDIX O

# ECONOMIC ANALYSIS OF ROADLESS ALTERNATIVE WITH SEASONAL DRILLING

Northern Economics

February 21, 2017

Stacie McIntosh
Arctic Field Office
Bureau of Land Management
1150 University Avenue
Fairbanks, Alaska 99709

Dear Ms. McIntosh:

This letter report transmits our findings on the economic analysis related to the Greater Mooses Tooth 2 (GMT2) project proposed by ConocoPhillips Alaska, Inc. (CPAI). This report is specifically focused on Alternative D2, the alternative with both a limited access restriction (no permanent road access) and a seasonal drilling restriction.

This letter report contains the following sections:

- Executive Summary
- Introduction and Purpose
- Approach
- Data Sources
- Oil Industry Rates of Return
- Findings and Comparisons

## Executive Summary

Based on feedback from the Bureau of Land Management, CPAI requested an independent analysis to evaluate the project economics of Alternative D2, one of the alternatives being considered for the proposed Greater Mooses Tooth 2 (GMT2) development. This economic analysis was requested to support CPAI's application for environmental permits. The primary objective of the analysis was to determine whether Alternative D2 would be economically feasible given its restrictions-- development without permanent road access to the facility and seasonal drilling.

The results of our economic analysis indicate that Alternative D2 would not be economic. The environmental restrictions noted above would negatively impact the economics of the proposed project.

Two oil price scenarios were considered in the analysis: 1) the latest Energy Information Administration's long-term price projections (Annual Energy Outlook 2016 with projections to 2040, released on September 15, 2016); and 2) the latest Alaska Department of Revenue's (ADOR) price projections (Revenue Sources Book Spring 2016, released on April 7, 2016).

### *EIA Price Scenario*

The results show that under the EIA price scenario (which has an average long-term price of about $123/barrel in 2015 $), and assuming a 10 percent real discount rate, Alternative D2 would be uneconomic with a negative discounted after-tax cash flow of -$554 million. This is due to both the seasonal drilling restriction and the limited access restriction. The seasonal drilling restriction would cause a delay in oil production, the subsequent monetizing of the oil resource, and would lower total oil production. Furthermore, without year-round road access, a number of facilities and services that would be provided at Alpine would need to be built at the GMT2 drill site resulting in a substantial increase in capital and operating costs.

### *ADOR Price Scenario*

As expected, the results under the ADOR price scenario are similar. Given this low oil price scenario, with an average price of about $62 per barrel of oil in 2015 $, the GMT2 development would not be economic, assuming a 10 percent real discount rate. Discounted EMV for Alternative D2 was estimated to be -$759 million.

## Introduction and Purpose

CPAI, as operator of the Greater Mooses Tooth Unit (GMTU) is proposing to produce hydrocarbon resources from a surface location on federal oil and gas leases in the NPR-A. The proposed Greater Mooses Tooth 2 Development Project (GMT2) is the second project proposed to be developed in the GMTU, in the Northeast NPR-A on Alaska's North Slope. The first project is GMT1, where production is expected to begin the fourth quarter of 2018. GMT2 was formerly known as the CD7 development production pad, one of the five drill sites comprising the Alpine Satellite Development Plan (ASDP), for which in 2004 a Final Environmental Impact Statement was prepared by the Bureau of Land Management (BLM). GMT2 was also analyzed in the 2012 NPR-A Integrated Activity Plan. In 2014, GMT2 development was considered as a reasonably foreseeable future action in the cumulative effects analysis of the Supplemental EIS prepared by BLM for GMT1 Development. In October of 2015, a modified NEPA Analysis Document (MNAD) was prepared by ConocoPhillips Alaska, Inc. (CPAI) to assist federal, state, and North Slope Borough agencies in evaluating CPAI's permit applications for the GMT2 Project by considering relevant new information to determine whether the impacts of the proposed project are still within the range of impacts analyzed in the previous environmental impact studies noted above. CPAI requested this additional analysis following feedback given by the BLM to support the environmental permit process. A similar independent economic analysis was requested by the BLM to support the Supplemental EIS for the GMT1 development.

The currently proposed GMT2 Project will include a drill site on Native selected land in the GMTU, with an access road, pipe rack, and pipelines on Native and federal lands to GMT1. The project will produce 3-phase hydrocarbons (oil, gas, and water) which will be carried by pipeline (across Native and federal lands within the NPR-A and Native and state lands outside) to the ACF at CD1 for processing. A new miscible injectant (MI) pipeline will be constructed on state land from the tie-in location north of Colville Delta 4 North. Gravel will be obtained from the Arctic Slope Regional Corporation (ASRC) mine site outside the NPR-A. Sales quality crude oil produced at the ACF will be transported from CD1 via the existing Alpine Sales Oil Pipeline and Kuparuk Pipeline to the TAPS for shipment to market.

CPAI's proposed alternative (Alternative A) includes a drill pad, a gravel access road to connect to the proposed GMT1 development, and pipelines. CPAI proposes to construct the GMT2 facilities on a 2-year construction schedule in 2019 and 2020. Drilling for Alternative A is expected to begin in May of Year 2, with first oil expected at the end of Year 2. Drilling is anticipated to continue year-round for 7

years to complete up to 48 wells. Operations is currently estimated to be 30 years post construction. Table 1 provides a summary of the proposed infrastructure for the GMT2 Project.

**Table 1. Summary of Infrastructure for GMT2 Alternative A, Proposed Action**

| Component | Alternative A Proposed Action |
|---|---|
| Gravel Drill Pad | 14.0 acres |
| Wells | up to 48 wells |
| GMT1-GMT2 Access Road | 8.1 miles, 62.8 acres |
| Subsistence Tundra Access Road Pullouts | 3 pullouts, 1.2 acres (0.4 acre each) |
| Elevated Pipelines on VSMs | 8.6 miles from GMT2 to GMT1; 0.1 acres<br>9.8 miles, crude oil pipeline from CD5 to CD1/ACF (on existing VSMs)<br>3.3 miles, MI pipeline from CD4/CD5 intersection to CD1/ACF (on existing VSMs) |
| Bridges | None |
| Gravel Supply | ASRC mine site |
| Total Gravel Footprint | 78.0 acres |
| Total Gravel Requirement | 671,300 cubic yards |
| Ice Roads | 52.6 miles (Year1)<br>43.9 miles (Year2) |

Source: Modified NEPA Analysis Document, CPAI 2015.

In addition to the proposed alternative, two other alternatives are being evaluated in consideration of anticipated environmental restrictions. Information on these alternatives is taken from the Modified NEPA Analysis Document prepared by CPAI.

**Alternative D1** (Roadless Access to GMT2) is similar to Alternative A, but without a gravel access road from GMT1 to GMT2 and the rest of the Alpine field development area. Access to the GMT2 site would be by aircraft and ice road during the winter. Alternative D1 includes a drill pad, an air strip and associated facilities, a local access road, and pipelines. The airstrip provides year-round access to GMT2 in lieu of a gravel road. A local gravel access road would connect the drill pad, occupied pad, and air access facilities (airstrip and apron). During winter, ice roads would be constructed to access the site. Movement of the drill rig to and from other drill sites would be limited to the ice road season restricting the ability to mobilize and demobilize the rig for work at other drill sites when it cannot work at GMT2. Construction and drilling schedule is similar to Alternative A.

With limited surface access, certain services, equipment, and supplies otherwise provided at the CD1/ACF would need to be duplicated at the drill site. A full-time workforce at GMT2 would also be required; hence onsite housing facilities will be required (an onsite occupied structure pad will be built). GMT2 would be re-supplied during the ice road season, requiring long-term storage of drilling and operating fluid and supplies. A new mud plant and bulk cement facility would be required for year-round drilling because the existing plant at CD1/ACF must remain in place to service drilling operations at the other satellites. Onsite wastewater and solid waste treatment or management would be required.

The need for additional facilities at GMT2 under this alternative results in much higher capital expenditures compared to Alternative A.

**Alternative D2**, which is the focus of this analysis, is very similar to Alternative D1 with the exception that a potential seasonal drilling restriction would preclude drilling activities when surface access (i.e., ice road) is not available. Drilling would be restricted to the time period when an ice road is available from GMT2 and GMT1, typically February to April (seasonal drilling). Once construction is completed,

ice roads would be constructed annually along the same route for 37 years to support vehicle access for drilling and operation. Operation would be year-round. The restriction to seasonal drilling would extend the drilling period and delay production and monetization of the oil resources.

This restriction would result in about an 80-day drilling season, including the time to mobilize and de-mobilize the drilling rig from GMT2, which could result in about 1.5 wells being drilled per season.

The MNAD prepared by CPAI contains more detailed information regarding the alternatives being considered for the GMT2 development.

## Approach

To conduct the analysis, we built upon the economic model developed by the Alaska Department of Natural Resources that was originally designed to assist interested parties in evaluating after-tax cash flows of oil and/or gas developments on State leases in Cook Inlet and Alaska's North Slope (ANS). We used the same model in the work we conducted for the Bureau of Land Management to assess the economic merits of the proposed GMT1 development. The DNR North Slope model was modified and calibrated for both the GMT1 and GMT2 economic evaluation.

The DNR model is based on the current fiscal regime; it has a number of input cells that are fixed due to statutes or regulations but there are a considerable number of inputs required for the model to accurately reflect a proposed project. The major inputs required for the analysis include:

1. Capital expenditures (CAPEX)
2. Operating expenditures (OPEX)
3. Projected production volumes
4. Tariffs/transportation costs
5. Crude oil price forecasts

The economic feasibility of the project alternatives were assessed using the following metrics—

1. The **Internal Rate of Return (IRR**) is the discount rate that makes the net present value of all cash flows from a particular project equal to zero. The higher the discount rate the more attractive the project.
2. The **Expected Monetary Value** is the discounted after-tax cash flow; higher numbers are preferred and negative after-tax cash flows would likely indicate that the operator would not proceed with the project.
3. The **Discounted Profitability Index** is similar to a benefit-cost ratio with the discounted after-tax cash flow divided by the discounted CAPEX. A ratio less than 1 would indicate that the project is not profitable.

## Data Sources

***Cost Data.*** The cost data presented by CPAI in the Modified NEPA Analysis Document (MNAD) for GMT2 were reviewed and compared to other data sources available to Northern Economics. A primary source of data for this work were capital and operating cost estimates developed by IMV Projects, Calgary, Alberta and independent research conducted by Northern Economics for an economic model that the two firms developed for the Bureau of Ocean Energy Management (BOEM). The model, called MAG-PLAN Alaska, was an update of an earlier model developed in the late 1990s and early 2000s. While the model focuses on OCS exploration, development, and production activities, it also has capital

cost and operating cost data related to a number of onshore activities and facilities (e.g., onshore pipelines, gravel pad and road construction, ice road construction, production facilities, camps, etc.). These costs were developed from interviews with contractors and service providers operating on the North Slope in 2010, along with extensive internet research. Additional research was undertaken to fill in data gaps and update the cost data to reflect changes since 2010. For example, information on day rates and total costs per day for drilling onshore wells on the North Slope have increased and subsequently decreased since 2010. The IHS Upstream Capital Cost Index provides information on historical trends in upstream costs (the index tracks the costs of equipment, facilities, materials and personnel (both skilled and unskilled) used in the construction of a geographically diversified portfolio of 28 onshore, offshore, pipeline and LNG projects). Generally, costs vary depending on business cycles. If future oil prices will more closely follow the DOR forecasted prices (a lower price scenario than the EIA price forecast) then future upstream costs could be lower than current and 2010 costs.

***Oil Price Projections.*** Two oil price scenarios were considered in the analysis:

1) Energy Information Administration's (EIA) long-term price projections (Annual Energy Outlook 2016 with projections to 2040, released on September 15, 2016); and

2) Alaska Department of Revenue's (ADOR) price projections (Revenue Sources Book Spring 2016, released on April 7, 2016).

Both of these projections are publicly available and therefore are usually used in economic analyses of this nature. The oil price forecasts considered in the analysis are the latest available data from the two sources. Table 2 shows the price per barrel of oil for the years covering this analysis (2020 to 2050) under the two price scenarios.

The EIA prices shown in the table are Brent prices expressed in real 2015 dollars. The EIA projections cover the period 2016 to 2040; prices beyond 2040 were extrapolated using the annual rate of change (2.9 percent year-to-year change) for the period 2020 to 2040 as reflected in the EIA price forecast.

The ADOR price projections shown in the table are real 2015 dollars for ANS West Coast. ADOR projections only cover the period 2016 to 2025; prices beyond 2025 were extrapolated using the annual rate of change (1.5 percent year-to-year change) for the last 5 years of the projections (2020 to 2025).

Note that the ANS West Coast tracks closer to Brent than WTI since most imported crudes to the West Coast which compete with ANS are based on the Brent benchmark, thus ANS West Coast moves in a manner similar to Brent.

As shown in Table 2, the EIA forecasts much higher oil prices compared to ADOR. The long-term average price under the EIA projection is about $123 per barrel of oil compared to about $62 under the ADOR projection.

**Table 2. Projected Real Price per Barrel of Oil (2015 $) based on latest ADOR and EIA Price Projections**

| Year | ADOR Price Projection | EIA Price Projection |
|---|---|---|
| 2020 | 48.62 | 76.57 |
| 2021 | 52.60 | 81.16 |
| 2022 | 52.56 | 84.65 |
| 2023 | 52.54 | 87.11 |
| 2024 | 52.51 | 89.15 |
| 2025 | 52.49 | 91.59 |
| 2026 | 53.30 | 94.63 |
| 2027 | 54.12 | 97.18 |
| 2028 | 54.95 | 99.33 |
| 2029 | 55.80 | 102.23 |
| 2030 | 56.66 | 104.00 |
| 2031 | 57.53 | 107.23 |
| 2032 | 58.42 | 110.50 |
| 2033 | 59.32 | 113.85 |
| 2034 | 60.24 | 117.39 |
| 2035 | 61.17 | 119.64 |
| 2036 | 62.11 | 123.29 |
| 2037 | 63.07 | 125.51 |
| 2038 | 64.04 | 129.21 |
| 2039 | 65.03 | 132.08 |
| 2040 | 66.03 | 136.21 |
| 2041 | 67.05 | 140.19 |
| 2042 | 68.08 | 144.29 |
| 2043 | 69.13 | 148.51 |
| 2044 | 70.20 | 152.84 |
| 2045 | 71.28 | 157.31 |
| 2046 | 72.38 | 161.91 |
| 2047 | 73.50 | 166.64 |
| 2048 | 74.63 | 171.51 |
| 2049 | 75.78 | 176.52 |
| 2050 | 76.95 | 181.68 |

Sources: Energy Information Administration's Annual Energy Outlook (EIA, 2016) and Alaska Department of Revenue's Spring Revenue Sources Book (ADOR, 2016).

***Production Volumes.*** Annual production volumes for Alternative D2 were estimated by Northern Economics based on the assumption that the seasonal drilling restriction would result in an 80-day drilling season, with about 1.5 wells drilled per season. The production schedule under Alternative D2 is delayed by several years compared to Alternatives A and D1. The annual production volumes for Alternative A and D1 are presented in the MNAD.

***Pipeline and marine transportation costs forecasts.*** These are based on the 2016 Revenue Sources Book with the average ANS feeder line tariff of $1 subtracted from the ADOR estimate and replaced with known tariffs for Alpine and Kuparuk pipelines, plus an estimated operating cost for the GMT1 and GMT2 multiphase flowlines.

***OPEX data.*** Data are not readily available to estimate the various OPEX categories in the DNR model, so the average ANS OPEX data for the North Slope from the Revenue Sources Book was used.

## Oil Industry Rates of Return

The outputs from the DNR model provide several metrics to consider when evaluating whether a proposed alternative is viable. However, the perspective of viability may be much different for a public agency compared to private industry, which may require higher rates of return on their investments.

The threshold rate of returns and the associated discount rate for most major oil companies are usually closely held and considered proprietary information and typically are not available in the public domain. To assist in a review of oil industry rates of return, we previously reached out to Mr. Scott Susich, a consultant with Energy Management Institute, and Mr. Barry Rodgers of Rodgers Oil and Gas Consulting. Mr Susich and Mr. Rogers have lengthy experience in the oil and gas industry and also teach Petroleum Economics and related courses.

In general, the rates of return for evaluating projects that they have seen in the industry over the past few years range from 8 to 12 percent with 10 percent (real) being the most common number. If there is an assumption of 2 percent inflation, then the nominal rate of return would be 12.2 percent.[1] A 10 percent real discount rate is also the number most commonly seen in oil and gas industry quarterly or annual reports where companies are demonstrating to investors the value of their known and probable reserves. As noted by the two experts, the rate of return can help in ranking projects, but when the rates are close, other factors such as the after-tax cash flow are used to provide further distinction with the largest after-tax cash flows being preferred. Thus, a project may meet the rate of return hurdle but the after-tax cash flow or other factors may not be sufficient to meet a company's requirements.

The DNR model as modified by Northern Economics uses a 10 percent real discount rate.

## Findings and Comparisons

The findings under each of the price scenarios considered are presented below.

**Energy Information Administration's Annual Energy Outlook Price Scenario:**

Table 3 presents the outputs from the modified DNR model for Alternative D2 under the EIA price scenario.

The Expected Monetary Value is the discounted after-tax cash flow, so higher numbers are preferred. Alternative D2 has a negative after-tax cash flow, hence, the operator would not likely proceed with this project alternative unless significant CAPEX or OPEX changes were possible to generate positive after tax cash flows.

[1] The nominal rate of return is calculated as (1+0.1)*(1+0.02)-1 = 0.122 or 12.2% where 0.1 equals the 10 percent real rate of return and the 0.02 is the inflation rate of 2 percent.

**Table 3. Estimated Financial Metrics and Taxes under EIA Price Scenario: Alternative D2**

| Model Outputs (Discounted to 2015 $) | Value |
|---|---|
| Discounted Expected Monetary Value (EMV 2015$ MM) | -$554 |
| Discounted Profitability Index | 0.6 |
| Internal Rate of Return (%) | 3% |
| | |
| Discounted Royalties Paid (2015$ MM) | $148 |
| Discounted State and Local Taxes (2015$ MM) | -$188 |
| Discounted Federal Taxes (2015$ MM) | $13 |

Source: Northern Economics, Inc.

The Discounted Profitability Index (DPI) is similar to a benefit-cost ratio with the ratio of the discounted after-tax cash flow to the discounted CAPEX. Using this indicator, Alternative D2 is not profitable given a DPI of less than 1.

The Internal Rate of Return (IRR) is the discount rate that makes the net present value of all cash flows from a particular project equal to zero. Thus, the higher the discount rate, the more attractive the project. As noted above, typical oil industry threshold rate of return requirement can range from 8 to 12 percent; with 10 percent (real) being the most common number cited in economic analyses. Alternative D2 has an IRR of 3 percent, well below the threshold requirement for the oil industry.

Table 3 above also shows some metrics that are not oriented to the producer but rather provide an indicator of returns to other public and private parties.

Alternative D2 is estimated to generate royalties amounting to $148 million. This amount however would be much lower compared to the royalties generated if there were no delays in oil production.

State and local taxes are primarily severance, ad valorem (property), and corporate income taxes. Local governments only participate in the shared ad valorem taxes; the other taxes are reserved for the state. The state also has various tax credits that can partially offset the severance tax. The net present value of the state and local tax revenues is negative for Alternative D2 due to the large amount of tax credits issued early in the project life and the lower production volumes early in the production life due to the seasonal drilling restriction.

Federal tax is primarily corporate income tax which is also affected by the net (total tax revenue less tax credits) taxes paid to the state. As state tax credits increase the result is lower net state tax revenue which results in greater reported income to the operator for federal income tax purposes. Alternative D2 is estimated to generate about $13 million in federal taxes.

### Alaska Department of Revenue's Price Scenario

Table 4 presents the results of the analysis under the ADOR price scenario. The latest oil price projection published by the Alaska Department of Revenue (Revenue Sources Book Spring 2016) shows lower expected oil prices compared to the EIA long-term forecast. ADOR projects an average price of $62 per barrel in real prices (2015 $) while the EIA price forecast averages to about $123 per barrel (in 2015 $) over the timeframe of the analysis (2020 to 2050).

As expected, under this lower oil price scenario, the results show that Alternative D2 is uneconomic.

As shown in Table 4, royalties under this price scenario are estimated to be about $56 million for Alternative D2. Because of the lower oil prices under this scenario, royalties are less than the estimated

royalties under the EIA price scenario. The discounted state and local taxes as well as federal taxes, or loss carry-forwards are negative under this low oil price scenario.

**Table 4. Estimated Financial Metrics and Taxes under ADOR Price Scenario: Alternative D2**

| Model Outputs (Discounted to 2015 $) | Value |
|---|---|
| Discounted Expected Monetary Value (EMV 2015$ MM) | -$759 |
| Discounted Profitability Index | 0.4 |
| Internal Rate of Return (%) | N/A |
| | |
| Discounted Royalties Paid (2015$ MM) | $56 |
| Discounted State and Local Taxes (2015$ MM) | -$310 |
| Discounted Federal Taxes (2015$ MM) | -$116 |

Source: Northern Economics, Inc.

Thank you for the opportunity to be involved in this interesting project. If you have any questions concerning this letter, report please contact me or Dr. Leah Cuyno at 907.274.5600.

Sincerely,

Patrick L. Burden

Patrick L. Burden
Principal Economist

Northern Economics

# Memorandum

**Date:** July 9, 2018

**To:** Stephanie Rice, Alaska Bureau of Land Management

**From:** Patrick Burden and Leah Cuyno

**Re:** GMT-2 Updated Alternative D2 Analysis

This memorandum transmits the results of the updated economic analysis of Alternative D2 of the Greater Mooses Tooth 2 (GMT2) development as described in the Draft Supplemental EIS.

This analysis considers the following major updates:

1. A change in the Federal corporate tax rate that went into effect in January 2018 with the passage of the "Tax Cuts and Jobs Act".
2. Changes in certain provisions of the State of Alaska's oil production tax.
3. New oil price projections published by the Alaska Department of Revenue and the Energy Information Administration.
4. Changes in capital and operating cost estimates.
5. Revisions to the projected annual oil production estimates.

### *Fiscal Terms*

The analysis was updated using a revised cash flow model developed by the Alaska Department of Natural Resources (ADNR) that incorporated recent changes in both State and Federal taxes. Since the beginning of 2018, the Federal corporate income tax rate in effect is a flat rate of 21 percent. A summary of the key provisions of Alaska's oil production tax as of January 1, 2018 is presented in the table below.

| Provision | Terms: Oil Production in the Alaska North Slope |
|---|---|
| Base Tax Rate | 35% (applied to production tax value) |
| Minimum Tax Floor | Up to 4% of the Gross Value at Point of Production. 4% rate applies when the Alaska North Slope price is more than $25/barrel. (applied to Gross Value at Point of Production) |
| Gross Value Reduction | For new oil, 20% or 30% of gross value excluded from the Base tax calculation; limited to first seven years of production; benefit ends early if the average ANS price exceeds $70 for any three years. |
| Per-Taxable-Barrel Credit for Non-GVR Production | Sliding scale $0/barrel to $8/barrel. $8 credit applies when wellhead price is less than $80/ barrel. Cannot be used to reduce tax below the minimum tax. Cannot be carried forward to subsequent year. |
| Per-Taxable-Barrel Credit for GVR Production | $5/barrel, no sliding scale. Cannot be carried forward to subsequent year. When used alongside non-GVR eligible oil credit, cannot reduce tax below the minimum tax. |
| Lease Expenditures Carryforward Deduction | Beginning Jan. 1, 2018, a company may carry forward lease expenditures not deducted against tax, and may apply in future year to reduce liability to minimum tax, contingent on the production from the area earned. Carryforwards reduce in value by one-tenth each year beginning in the eighth or 11th year after it is earned. |

***Oil Price Projections.*** Two oil price scenarios were considered in the analysis:

1) Energy Information Administration's (EIA) long-term price projections (Annual Energy Outlook 2018 with projections to 2050, released on February 6, 2018); and
2) Alaska Department of Revenue's (ADOR) price projections (Revenue Sources Book Spring 2018, released on March 16, 2018).

The table below shows the price per barrel of oil in real dollars (2017 $) for the years covering the production phase of the analysis. The ADOR price projections shown in the table are ANS West Coast. ADOR projections only cover the period 2018 to 2027; prices beyond 2027 were extrapolated using the annual rate of change for the period 2018 to 2027. The long-term average oil price per barrel under the EIA projection is about $99.70 compared to about $60.80 under the ADOR projection.

**Projected Real Price per Barrel of Oil (2017 $) based on latest EIA and ADOR Price Projections**

| Year | EIA | ADOR |
|---|---|---|
| 2022 | 80.55 | 59.95 |
| 2023 | 82.95 | 60.38 |
| 2024 | 84.51 | 59.90 |
| 2025 | 85.70 | 60.26 |
| 2026 | 87.47 | 60.57 |
| 2027 | 88.66 | 60.04 |
| 2028 | 90.31 | 60.11 |
| 2029 | 91.80 | 60.19 |
| 2030 | 92.82 | 60.27 |
| 2031 | 94.87 | 60.34 |
| 2032 | 95.84 | 60.42 |
| 2033 | 97.17 | 60.50 |
| 2034 | 98.74 | 60.58 |
| 2035 | 99.87 | 60.65 |
| 2036 | 100.32 | 60.73 |
| 2037 | 102.77 | 60.81 |
| 2038 | 103.92 | 60.88 |
| 2039 | 104.87 | 60.96 |
| 2040 | 106.08 | 61.04 |
| 2041 | 107.21 | 61.12 |
| 2042 | 107.77 | 61.19 |
| 2043 | 108.46 | 61.27 |
| 2044 | 109.41 | 61.35 |
| 2045 | 110.04 | 61.43 |
| 2046 | 110.39 | 61.51 |
| 2047 | 111.14 | 61.58 |
| 2048 | 112.10 | 61.66 |
| 2049 | 112.99 | 61.74 |
| 2050 | 113.56 | 61.82 |

***Updated CAPEX Estimates.*** CAPEX estimates were updated based on data from the ADNR revised cash flow model, as well as information from Attanasi and Freeman (2007) that changed some of the allocation between CAPEX for facilities and CAPEX for development drilling. The revised cost data remained comparable to the CAPEX estimate used in the previous economic analysis of Alternative D2. The capital costs in the model were also adjusted to 2017 dollars using the IHS Upstream Capital Cost Index which provides information on historical trends in upstream costs (the index tracks the costs of equipment, facilities, materials and personnel (both skilled and unskilled) used in the construction of a geographically diversified portfolio of 28 onshore, offshore, pipeline and LNG projects).

***Updated OPEX Estimate.*** The annual operating cost estimate in the revised model reflects the prevailing operating costs in the Alaska North Slope- a fixed $/well/year estimate of $300,000 and a variable operating cost component of $10 per barrel of oil. These were the default values in the ADNR revised cash flow model.

***Revised Production Volumes.*** CPAI provided an updated oil production profile for their proposed project alternative (Alternative A). Given the increase in the total production volumes and the change in the decline rate, Northern Economics revised the annual production volumes for Alternative D2 accordingly. The revised production profile for Alternative D2 is based on the assumption that the seasonal drilling restriction would result in an 80-day drilling season, with 2 wells drilled per season. The production schedule under Alternative D2 is delayed by several years compared to Alternative A.

### *Findings*

The results show that Alternative D2 would not be economic under any of the price scenarios considered given the changes in fiscal terms, updated production volumes, and updated oil price assumptions and costs (see table below).

The results show that under the *EIA price scenario* (which has an average long-term price of about $99.7/barrel in 2017 $), and assuming a 10 percent real discount rate, Alternative D2 would be uneconomic with a negative discounted after-tax cash flow (Producer's NPV) of -$498 million, and an Internal Rate of Return (IRR) of 6 percent. This IRR is below the discount rate (10 percent) or the typical threshold for oil industry rate of return.

The results under the *ADOR price scenario* are similar. Given an even lower oil price scenario, with an average price of about $60.8 per barrel of oil in 2017 $, the discounted Producer's NPV for Alternative D2 was estimated to be -$871 million with an IRR of 1 percent.

**Estimated Financial Metrics under the ADOR and EIA Price Projections**

| Model Outputs (Discounted) | Expected Value | |
|---|---|---|
| | ADOR Price Scenario | EIA Price Scenario |
| Producer's Net Present Value (NPV) ($MM) | -871 | -498 |
| Internal Rate of Return (IRR) (%) | 1.1% | 6.0% |
| | | |
| State Royalty Revenue ($MM) | $83 | $132 |
| State Property Tax ($MM) | $168 | $168 |
| State Production Tax ($MM) | $22 | $111 |
| Federal Royalty Revenue ($MM) | $79 | $132 |
| Federal Corporate Income Tax | $51 | $468 |

# APPENDIX P

# ALPINE OIL DISCHARGE PREVENTION AND CONTINGENCY PLAN

ConocoPhillips

# Oil Discharge Prevention and Contingency Plan

## Alpine Field and Satellites and Alpine Pipeline System

Western North Slope, Alaska

Approved February 2018

ADEC Plan No. 17-CP-4140
EPA FRP AKA0236
DOT Sequence No. 1476

BLANK PAGE

THE STATE
of ALASKA
GOVERNOR BILL WALKER

Department of
Environmental Conservation
DIVISION OF SPILL PREVENTION AND RESPONSE
Prevention, Preparedness, and Response Program
555 Cordova Street
Anchorage, AK 99501-2617
Main: 907-269-7557
Fax: 907-269-7687
www.dec.alaska.gov

Facility #: 5138

**OIL DISCHARGE PREVENTION AND CONTINGENCY PLAN APPROVAL**

February 16, 2018

Jeanie Shifflett
ConocoPhillips Alaska, Inc.
PO Box 100360
Anchorage, AK 99510

Subject: **ConocoPhillips Alaska, Inc. Alpine Field and Satellites and Alpine Pipeline System Oil Discharge Prevention and Contingency Plan, ADEC Plan #: 17-CP-4140; Plan Approval**

Dear Ms. Jeanie Shifflett:

The Alaska Department of Environmental Conservation (department) has completed its review of the plan renewal application package for the ConocoPhillips Alaska, Inc. Alpine Field and Satellites and Alpine Pipeline System Oil Discharge Prevention and Contingency Plan (plan) that was received on July 28, 2017. The department coordinated the State of Alaska's public review for compliance with 18 AAC 75, using the review procedures outlined in 18 AAC 75.455. Based on our review, the department has determined that your plan is consistent with the applicable requirements of the referenced regulations and is hereby approved.

This approval applies to the following plan:

| | |
|---|---|
| Plan Title: | **ConocoPhillips Alaska, Inc. Alpine Field and Satellites and Alpine Pipeline System Oil Discharge Prevention and Contingency Plan** |
| Documents: | **Alaska Clean Seas Technical Manual** |
| Plan Holder: | **ConocoPhillips Alaska, Inc., Anchorage, AK** |
| Covered Facilities: | **Production facilities at CD1, CD2, CD3, CD4, CD5, and GMT1; the 14-inch crude oil transmission pipeline and 2-inch diesel line from Alpine's CD1 to Kuparuk River Unit's CPF2; and associated flow lines, regulated tanks, and facility piping** |

**PLAN APPROVAL:** The approval for the referenced plan is hereby granted **effective February 16, 2018.** A Certificate of Approval stating that the department has approved the plan is enclosed.

**EXPIRATION:** This approval **expires February 15, 2023.** Following expiration, Alaska law prohibits operation of the facility until an approved plan is once again in effect.

**CONDITION(S) OF APPROVAL:** The approval is subject to the following condition:

1. <u>**Blowout Contingency Plan.**</u> A copy of the Blowout Contingency Plan (BCP) must be maintained at Alpine and made available to the department upon request. A copy of the BCP must be made available for review by the Alaska Oil and Gas Conservation Commission upon request.

   *This condition is necessary to ensure that the plan holder is prepared to control a potential well blowout. 18 AAC 75.425(e)(1)(I), 18 AAC.445(d)(2), and 18 AAC 75.480.*

**TERMS:** The approval is subject to the following terms:

1. **PROOF OF FINANCIAL RESPONSIBILITY:** The plan holder has provided the department with proof of financial responsibility per the requirements of AS.46.04.040 and 18 AAC 75.205 – 18 AAC 75.290.

2. **PUBLICATION OF PLAN:** The plan holder shall provide copies of the approved plan to the parties and in the format indicated in the enclosed distribution list in accordance with 18 AAC 75.408(c) not later than 30 days of this approval.

3. **AMENDMENT:** Except for routine updates under 18 AAC 75.415(b), an application for approval of an amendment must be submitted by the plan holder and approved by the department before a change to this plan may take effect. This is to ensure that changes to the plan do not diminish the plan holder's ability to respond to a discharge and to evaluate any additional environmental considerations that may need to be taken into account (18 AAC 75.415).

4. **RENEWAL:** To renew this plan, the plan holder must submit an application package to the department no later than 180 days prior to the expiration of this approval. This is to ensure that the submitted plan is approved before the current plan in effect expires (18 AAC 75.420).

5. **REVOCATION, SUSPENSION OR MODIFICATION**: This approval is effective only while the plan holder is in compliance with the plan as defined in AS 46.04.030(r) and with all of the terms and conditions described above. The department may, after notice and opportunity for a hearing, revoke, suspend, or require modification of the approved plan if the plan holder is not in compliance with the plan or for any other reason stated in AS 46.04.030(f). In addition, Alaska law provides that a vessel or facility that is not in compliance with a plan may not operate (AS 46.04.030). The department may terminate approval prior to the expiration date if deficiencies are identified that would adversely affect spill prevention, response or preparedness capabilities.

6. **DUTY TO RESPOND**: Notwithstanding any other provisions or requirements of this plan, a person causing or permitting the discharge of oil is required by law to immediately control, contain, and cleanup the discharge regardless of the adequacy or inadequacy of the plan (AS 46.04.020).

7. **NOTIFICATION OF NON-READINESS**: The plan holder must notify the department in writing, within 24 hours, after any significant response equipment as specified in the plan is removed from its designated storage location or becomes non-operational. This notification must provide a schedule for equipment substitution, repair, or return to service as described in 18 AAC 75.475(b).

8. **CIVIL AND CRIMINAL SANCTIONS**: Failure to comply with the plan may subject the plan holder to civil liability for damages and to civil and criminal penalties. Civil and criminal sanctions may also be imposed for any violation of AS 46.04, any regulation issued thereunder or any violation of a lawful order of the department.

9. **INSPECTIONS, DRILLS, RIGHTS TO ACCESS, AND VERIFICATION OF EQUIPMENT, SUPPLIES, AND PERSONNEL**: The department has the right to verify the ability of the plan holder to carry out the provisions of this plan and to access inventories of equipment, supplies, and personnel through such means as inspections and discharge exercises without prior notice to the plan holder. The department has the right to enter and inspect the facility in a safe manner at any reasonable time for these purposes and to otherwise ensure compliance with the plan and the terms and conditions [AS 46.04.030(e) and AS 46.04.060]. The plan holder shall conduct exercises for the purpose of testing the adequacy of the plan and its implementation (18 AAC 75.480 and 485).

10. **FAILURE TO PERFORM:** In granting approval of the plan, the department has determined that the plan, as represented to the department by the applicant in the application package for approval, satisfies the minimum planning standards and other requirements established by applicable statutes and regulations, taking as true all information provided by the applicant. The department does not warrant to the applicant, the plan holder, or any other person or entity: (1) the accuracy or validity of the information or assurances relied upon; (2) that the plan is or will be implemented; or (3) that even full compliance and implementation with the plan will result in complete containment, control or clean-up of any given oil spill, including a spill specifically described in the planning standards. The plan holder is encouraged to take any additional precautions and obtain any additional response capability it deems appropriate to further guard against the risk of oil spills and to enhance its ability to comply with its duty under AS 46.04.020(a) to immediately contain and clean up an oil discharge.

11. **COMPLIANCE WITH APPLICABLE LAWS**: The plan holder must adhere to all applicable state statutes and regulations as they may be amended from time to time. This approval does not relieve the plan holder of the responsibility to secure other federal, state, or local approvals or permits or to comply with all other applicable laws.

12. **INFORMAL REVIEWS AND ADJUDICATORY HEARINGS:** If aggrieved by the department's decision, the applicant or any person who submitted comments on the application not later than the close of the public comment period set out under 18 AAC 75.455 may request an adjudicatory hearing in accordance with 18 AAC 15.195 - 18 AAC 15.340 or an informal review by the Division Director in accordance with 18 AAC 15.185.

    **Informal review requests** must be delivered to the Director, Spill Prevention and Response, 555 Cordova Street, Anchorage, Alaska 99501, not later than 20 days of the issuance of the plan approval. A request for informal review is not required prior to making a request for adjudicatory hearing. A copy of the request should be sent to the undersigned.

    **Adjudicatory hearing requests** must be delivered to the Commissioner, Department of Environmental Conservation, 410 Willoughby Avenue, Suite 303, Juneau, Alaska 99801, within 30 days of the plan approval. If a hearing is not requested within 30 days, the right to appeal is waived. A copy of a hearing request must be served on the undersigned and the permit applicant as required by 18 AAC 15.200(c). A copy of the request must also be provided to the department in

an electronic format, unless the department waives this requirement because the requestor lacks a readily accessible means or the capability to provide the items in an electronic format.

13. **NOTICE OF CHANGED RELATIONSHIP WITH RESPONSE CONTRACTOR:** Because the plan relies on the use of response contractor(s) for its implementation, the plan holder must immediately notify the department in writing of any change in the contractual relationship with the plan holder's response contractor(s), and of any event including but not limited to any breach by either party to the response contract that may excuse a response contractor from performing, that indicates a response contractor may fail or refuse to perform, or that may otherwise affect the response, prevention, or preparedness capabilities described in the approved plan.

If you have any questions regarding this process, please contact Laurie Silfven at 907-269-7540 or laurie.silfven@alaska.gov.

Sincerely,

Graham Wood
Program Manager

Enclosures: Certificate of Approval, Number: 18CER-007
Summary of Basis for Decision
Approved Plan Distribution List

cc with enclosure:

Tom DeRuyter, ADEC
Laurie Silfven, ADEC
Colin Taylor, ADEC
C-Plan Reviewer, ADNR
DNR C-Plan, ADNR NRO
Bob Whittier, USEPA
Jason Walsh, ADNR
Jack Winters, ADF&G
Gordon Brower, NSB
Price Leavitt, NSB
USCG, Western Alaska Facilities
David Lehman, USDOT
Donna Wixon, BLM
Elisabeth Dabney, NAEC
Lois Epstein, The Wilderness Society
Planning Manager, Alaska Clean Seas

Alaska Department of Environmental Conservation

# Oil Discharge Prevention and Contingency Plan

## Certificate of Approval

| | | | |
|---|---|---|---|
| Certificate Number: | **18CER-007** | Plan Number: | **17-CP-4140** |
| Plan Title: | **ConocoPhillips Alaska, Inc. Alpine Field and Satellites and Alpine Pipeline System Oil Discharge Prevention and Contingency Plan** | | |
| Covered Facility(s): | **Production facilities at CD1, CD2, CD3, CD4, CD5, and GMT1; the 14-inch crude oil transmission pipeline and 2-inch diesel line from Alpine's CD1 to Kuparuk River Unit's CPF2; and associated flow lines, regulated tanks, and facility piping** | | |
| Plan Holder: | **ConocoPhillips Alaska, Inc.** | | |
| Address: | **P.O. Box 100360, Anchorage, AK 99510** | | |
| Telephone: | **907-265-6488** | Fax: | **907-265-6235** |
| Region(s) of Operation (18 AAC 75.495): | **North Slope** | | |
| Effective Date of Approval: | **February 16, 2018** | Expiration Date: | **February 15, 2023** |

**This approval is subject to the terms and conditions of the applicable Alaska Department of Environmental Conservation contingency plan approval letter dated 2/16/2018 and continuing compliance with the requirements of AS 46.04 and 18 AAC 75.**

2/16/2018

Graham Wood, Approving Authority — Date
Prevention, Preparedness and Response Program Manager

## CONOCOPHILLIPS ALASKA

## OIL DISCHARGE PREVENTION AND CONTINGENCY PLAN
## ALPINE FIELD AND SATELLITES AND ALPINE PIPELINE SYSTEM

## WESTERN NORTH SLOPE, ALASKA

### MANAGEMENT APPROVAL AND RESOURCE COMMITMENT STATEMENT

This Oil Discharge Prevention and Contingency Plan (ODPCP) is prepared for oil production facility and oil pipeline facility activities conducted by ConocoPhillips Alaska (COPA) within the Colville River Unit and Greater Mooses Tooth Unit on the Western North Slope of Alaska.

This plan is approved for implementation as herein described. Manpower, equipment, and materials will be provided as required in accordance with this plan.

Misty Alexa

March 5, 2018

Misty Alexa
Manager, Western North Slope Operations
ConocoPhillips Alaska

Date

# RECORD OF REVISIONS

| REVISION NUMBER | REVISION DATE | SUMMARY OF REVISION |
|---|---|---|
| 0 | February 2018 | 5-Year renewal revision of entire plan. |
| 1 | April 2018 | Section 3.1.1: update owner/operator information to "ConocoPhillips 100%". Revise Appendix D: Table D-3, add back two Rain for Rent tanks (#'s 254993, 255141); Table D-4, add seven Schlumberger tanks available for use (2SSF48256, 2SSF48257, 2SSF48258, 2SSF48259, 2SSF48260, 2SSF48261, 2SSF48262). |
| 2 | May 2018 | Section 1.8: update CD5 facility diagram to include tank farm and TTLA; Section 2.1.10 Table 2-3 to include CD5 TTLA; Appendix D: Table D-1 add tank CF-T-505031 and update product type for CF-T-50090. |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |

BLANK PAGE

# TABLE OF CONTENTS

# LIST OF FIGURES

# LIST OF TABLES

# LIST OF ACRONYMS

| | |
|---|---|
| °F | degrees Fahrenheit |
| °C | degrees Celsius |
| AAC | Alaska Administrative Code |
| ACF | Alpine Central Facilities |
| ACP | area contingency plan |
| ACS | Alaska Clean Seas |
| ADEC | Alaska Department of Environmental Conservation |
| ADF&G | Alaska Department of Fish and Game |
| ADNR | Alaska Department of Natural Resources |
| AFPM | American Fuel & Petrochemical Manufacturers |
| ANSI | American National Standards Institute |
| AOGCC | Alaska Oil and Gas Conservation Commission |
| API | American Petroleum Institute |
| ARRT | Alaska Regional Response Team |
| ASME | American Society of Mechanical Engineers |
| ATV | all-terrain vehicle |
| BAT | best available technology |
| bbl | barrels |
| BLM | U.S. Department of the Interior, Bureau of Land Management |
| BOP | blowout preventer |
| bopd | barrels of oil per day |
| boph | barrels of oil per hour |
| bpd | barrel per day |
| bph | barrels per hour |
| CERCLA | Comprehensive Environmental Response, Compensation, and Liability Act |
| CFR | Code of Federal Regulation |
| cfs | cubic feet per second |
| $CO_2$ | carbon dioxide |
| CP | cathodic protection |
| COPA | ConocoPhillips Alaska |
| CPF | Central Processing Facility |
| CS | Control Site |

| | |
|---|---|
| CTF | Containment Task Force |
| cu yd | cubic yard |
| DCS | distributed control system |
| DOT | U.S. Department of Transportation |
| DRA | drag reducing agent |
| EOC | Emergency Operations Center |
| EPA | U.S. Environmental Protection Agency |
| ERD | extended reach drilling |
| ESD | emergency shutdown |
| FBE | fusion bonded epoxy |
| FLIR | forward-looking infrared |
| FOSC | Federal On-Scene Coordinator |
| GIMAT | Global Incident Management Assist Team |
| GOR | gas-to-oil ratio |
| gpm | gallons per minute |
| HAZMAT | Hazardous Materials |
| HAZWOPER | hazardous waste operations and emergency response |
| HDD | horizontal directional drilling |
| HDPE | high density polyethylene |
| HMRT | hazardous materials response team |
| HSE | health, safety, and environment |
| IAP | Incident Action Plan |
| IARC | International Agency for Research on Cancer |
| IC | Incident Commander |
| ICS | Incident Command System |
| IMT | Incident Management Team |
| LEPC | Local Emergency Planning Committee |
| LOSC | Local On-Scene Coordinator |
| MAD | Mutual Aid Drill |
| MB | Mass Balance |
| MBLPC | Mass Balance Line Pack Compensation |
| mph | miles per hour |
| NACE | National Association of Corrosion Engineers |
| NGL | natural gas liquid |

| | |
|---|---|
| NIMS | National Incident Management System |
| NIST | National Institute of Standards and Technology |
| NPR-A | National Petroleum Reserve – Alaska |
| NPREP | National Preparedness for Response Exercise Program |
| NPWM | Negative Pressure Wave Monitoring |
| NRC | National Response Center |
| NSB | North Slope Borough |
| NSSRT | North Slope Spill Response Team |
| NTP | National Toxicology Program |
| ODPCP | Oil Discharge Prevention and Contingency Plan |
| OSC | On-Scene Commander |
| OSHA | Occupational Safety and Health Administration |
| OSRO | oil spill removal organization |
| PM | preventive maintenance |
| PPA™ | Pressure Point Analysis™ |
| PPE | personal protective equipment |
| ppm | parts per million |
| PRAC | primary response action contractor |
| PREP | Preparedness for Response Exercise Program |
| psi | pounds per square inch |
| psig | pounds per square inch gauge |
| PVC | polyvinyl chloride |
| QI | Qualified Individual |
| RCRA | Resource Conservation and Recovery Act |
| REIM | remote electrical-instrument module |
| RP | responsible party |
| RPS | response planning standard |
| RTTM | Real Time Transient Model |
| SCADA | Supervisory Control and Data Acquisition |
| scf/bbl | standard cubic feet per barrel |
| SIS | safety instrument system |
| SOP | Standard Operating Procedure |
| SPCC | Spill Prevention, Control, and Countermeasure |
| SPCO | State Pipeline Coordinator's Office |

| | |
|---|---|
| SRT | Spill Response Team |
| TF | Task Force |
| UC | Unified Command |
| UHF | ultra high frequency |
| ULSD | ultra-low sulfur diesel |
| USCG | U.S. Coast Guard |
| USFWS | U.S. Fish and Wildlife Service |
| VHF | very high frequency |
| VSM | vertical support member |
| WCD | worst case discharge |

BLANK PAGE

# INTRODUCTION

This Oil Discharge Prevention and Contingency Plan (ODPCP) is for the Alpine Field and Satellites and Alpine Pipeline System facilities located within the North Slope Borough, Alaska and on state lands within the Colville River Unit and federal lands of the National Petroleum Reserve – Alaska (NPR-A) within the Greater Mooses Tooth Unit. ConocoPhillips Alaska (COPA) is the operator of the facilities covered by this ODPCP. COPA's address, phone, and fax numbers are provided below:

ConocoPhillips Alaska
P.O. Box 100360
Anchorage, AK 99510-0360
Phone: (907) 276-1215

Street Address:
700 G Street
Anchorage, AK 99510-0360

The primary goal of this ODPCP is to prevent and/or limit the spread of a spill, thereby minimizing potential environmental impacts, and providing for the safety of personnel. Where the two may conflict, safety of personnel will always be given the first consideration.

Under Alaska Statute 46.04.030 a pipeline or production facility must operate in compliance with an approved ODPCP. This ODPCP addresses requirements for pipeline and production facility operations governed by the Alaska Department of Environmental Conservation (ADEC) under Title 18, Chapter 75 of the Alaska Administrative Code (18 AAC 75), as amended through March 23, 2017. This ODPCP addresses federal regulations of the U.S. Environmental Protection Agency (EPA) at Title 40 of the Code of Federal Regulations Part 112 (40 CFR 112) and regulations of the U.S. Department of Transportation (DOT) at 49 CFR 194, as mandated by the Oil Pollution Act of 1990. In addition, this ODPCP addresses environmental obligations required by the U.S. Department of the Interior Bureau of Land Management (BLM) under 43 CFR 3162.5

The major operations covered by this ODPCP include:

- Alpine Central Processing Facility;
- Production Drill Sites CD1, CD2, CD3, CD4 CD5, and GMT1;
- Production flowlines;
- Gas/water handling and injection facilities;
- Alpine crude oil transmission pipeline; and
- Alpine diesel pipeline.

COPA assumes responsibility for containment and cleanup of oil spills from its facilities and operations within the Alpine Field and Satellites and Alpine Pipeline System. COPA requires that contract companies and their employees adhere strictly to COPA safety and environmental policies and procedures while working on COPA lease holdings. Contractors are required to report all spills to Alpine Security.

COPA is a member of Alaska Clean Seas (ACS), which serves as the primary response action contractor for COPA operations on the North Slope. This ODPCP incorporates by reference, wherever applicable, the ACS *Technical Manual*, which consists of Volume 1, *Tactics Descriptions*, and Volume 2, *Map Atlas*. Volume 1 describes the tactics used to respond to a variety of spill situations. Volume 2 provides maps and a narrative description of resources at risk, as well as key response considerations by location.

## PLAN CONTENTS

The ODPCP format is consistent with the format required by 18 AAC 75. Facilities are located on private, local, state, and/or federal land, and are regulated by and subject to applicable legal provisions of North Slope Borough, State of Alaska, EPA, DOT, and BLM.

The following is a summary of principal contents of this ODPCP:

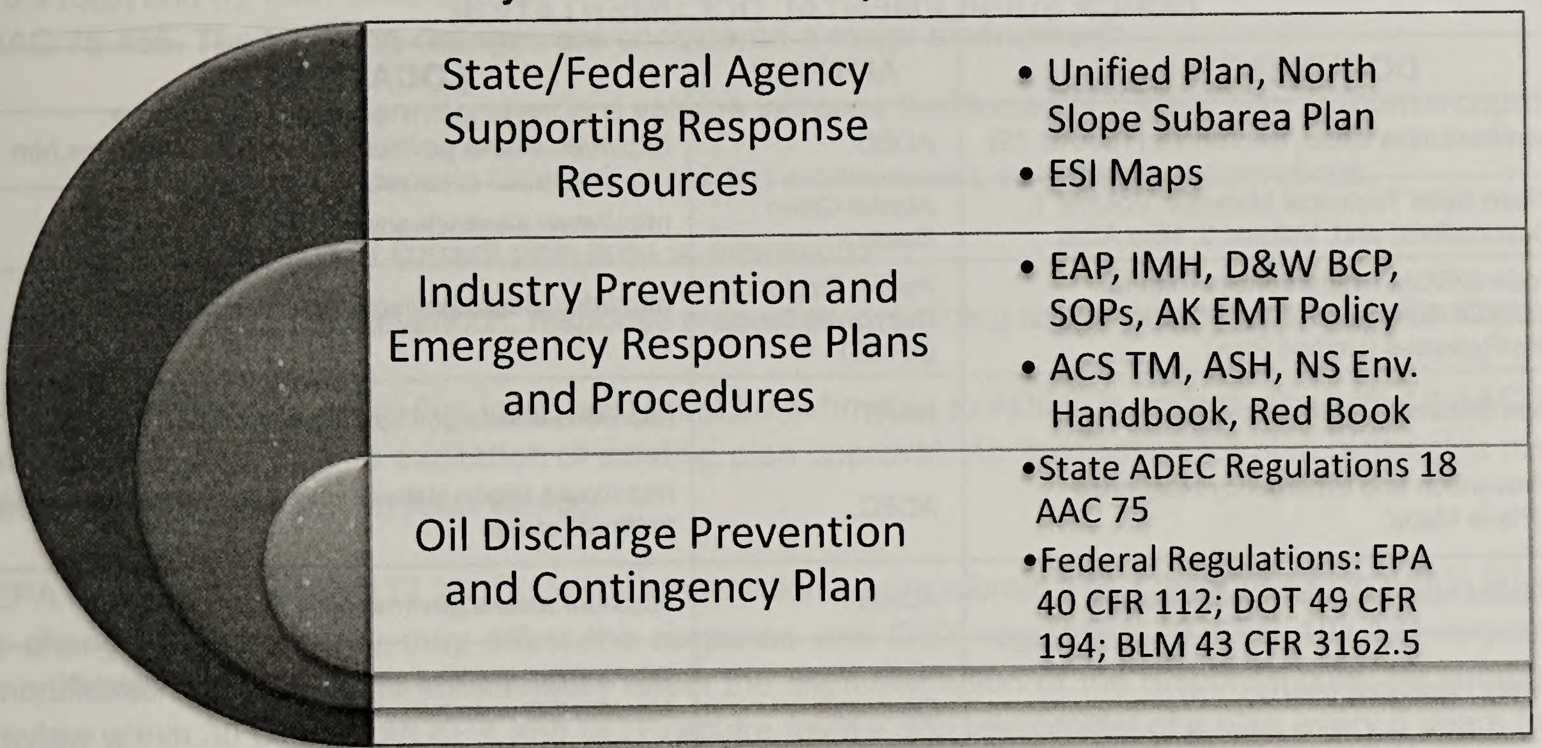
- **Part 1 – Response Action Plan:** provides information to guide responders during an incident. Information includes reporting and notification procedures, basic safety procedures, response communications, deployment and response strategies, and initial response procedures.
- **Part 2 – Prevention Plan:** provides detailed description of policies, best management practices, and prevention measures employed at facilities. Information is included on training programs, identified risks, historical spills, and measures taken to minimize potential environmental impact.
- **Part 3 – Supplemental Information:** provides an overview of facility operations, receiving environment, and supporting response information.
- **Part 4 – Best Available Technology:** provides analysis of facility spill prevention and response equipment to ensure it meets performance standards in 18 AAC 75.
- **Part 5 – Response Planning Standard:** presents a calculation of the applicable response planning standards and detailed basis for the calculation of reductions if applied to the response planning standard volume.
- **Appendices:** provide additional supporting information, including EPA, DOT, and BLM response plan cross-reference tables, facility spill history, and a list of regulated oil storage tanks subject to this ODPCP.

EPA and DOT regulations allow submission of an equivalent state response plan to meet federal response plan requirements [40 CFR 112.20(h) and 49 CFR 194.109, respectively]. Cross-reference tables are provided in the Appendices to demonstrate compliance with EPA and DOT requirements. This ODPCP is also in place to meet contingency and response plan requirements for development operations on federal lands within the NPRA; a cross-reference table is also provided in the Appendices to address BLM requirements.

## PLAN SUPPLEMENTAL DOCUMENTATION

This ODPCP is supported by additional document resources that provide key prevention and response information. These documents provide a robust framework of procedures, processes, tactics, strategies, and guidance for operational personnel and response teams. Figure I-1 shows the important referenced documents that support the ODPCP. In addition, the following table provides a listing of the supplemental documents COPA references for oil discharge prevention and response information. Key internal and external written materials are available at COPA emergency operation center facilities.

**FIGURE I-1**
**Key Prevention and Response Documents**



| ODPCP SUPPLEMENTAL DOCUMENTATION | | |
|---|---|---|
| **DOCUMENT** | **AUTHOR** | **LOCATION/LINK** |
| Alaska Administrative Code, Section 75 (18 AAC 75) | ADEC | http://dec.alaska.gov/commish/regulations/index.htm |
| Alaska Clean Seas Technical Manuals: Volume 1, Tactics Descriptions; and, Volume 2, Map Atlas | Alaska Clean Seas | http://www.alaskacleanseas.org. |
| Alaska Federal/State Preparedness Plan for Response to Oil & Hazardous Substance Discharges/Releases (Unified Plan) | Alaska Regional Response Team (ARRT) | http://dec.alaska.gov/spar/perp/plans/uc.htm |
| North Slope Subarea Contingency Plan | ARRT | http://dec.alaska.gov/spar/perp/plans/scp_ns.htm. |
| Alaska "Prevention and Emergency Response Subarea Plans Maps" | ADEC | http://www.asgdc.state.ak.us/maps/cplans/subareas.html#northslope. |
| State of Alaska land records – Alaska Mapper | ADNR | http://dnr.alaska.gov/mapper/ |
| Alaska Safety Handbook (ASH) | North Slope Operators | COPA EOC facilities and COPA internal internet Alaska HSE website. |
| COPA Alaska Emergency Management Teams Policy | COPA | COPA internal internet Emergency Plans homepage |
| COPA Incident Management Handbook | COPA | COPA EOC facilities and COPA internal internet Emergency Plans website. |
| COPA Emergency Action Plans | COPA | COPA EOC facilities and COPA internal internet Alaska HSE website. |
| COPA Drilling and Wells Emergency Preparedness Blowout Contingency Plan | COPA | COPA EOC facilities and COPA internal internet Emergency Plans website. |
| North Slope Environmental Field Handbook | COPA | COPA EOC facilities and COPA internal internet Alaska HSE website. |
| Alaska Waste Disposal and Reuse Guide | COPA | COPA EOC facilities and COPA internal intranet Alaska HSE website. |
| NOAA Environmental Sensitivity Index (ESI) Maps. | NOAA | http://response.restoration.noaa.gov/esi. |

## PLAN DISTRIBUTION

The ODPCP is available electronically on the ADEC Internet website, as per 18 AAC 75.460(b)(3). The ODPCP is distributed to COPA Management and staff as appropriate, and is maintained on the COPA intranet Emergency Plans website. Paper copies are located in COPA emergency operations centers. The Plan Administrator maintains a record of plan distribution. Federal, state and local agency personnel and external stakeholders are provided copies of the plan, upon request; however, COPA encourages use of the electronic copy posted to the ADEC Internet website to ensure use of the most recent version and to reduce waste.

## PLAN UPDATING AND RENEWAL

The ODPCP is reviewed annually and periodically updated when changes occur. Changes necessary to keep the ODPCP current for use in an emergency are submitted to ADEC as plan amendments and typically

are considered routine plan updates or minor amendments, in accordance with provisions of 18 AAC 75.415(b) and (f). Plan amendments that ADEC determines to be a major amendment are reviewed per 18 AAC 75.455. The following changes are considered a major amendment:

- Response planning standard volume increase that exceeds current plan response capabilities.
- Change in scenario location, receiving environment, or season of operations.
- Expansion of current plan area of operations.
- Change in prevention, response resources, or training above or below current plan capabilities.

Plan renewals occur every five years and must be submitted to ADEC in accordance with 18 AAC 75.408 at least 180 days prior to expiration of existing plan approval. An application for plan renewal is reviewed under the provisions of 18 AAC 75.455.

EPA regulation 40 CFR 112.20(d)(1) requires revision and resubmittal of a response plan within 60 days of a change that materially may affect the response and DOT regulation 49 CFR 194.121 requires that modifications, which could substantially affect the implementation of the response plan, be submitted for review within 30 days. Both EPA and DOT require review and resubmittal of a plan every 5 years from the last submittal or approval date.

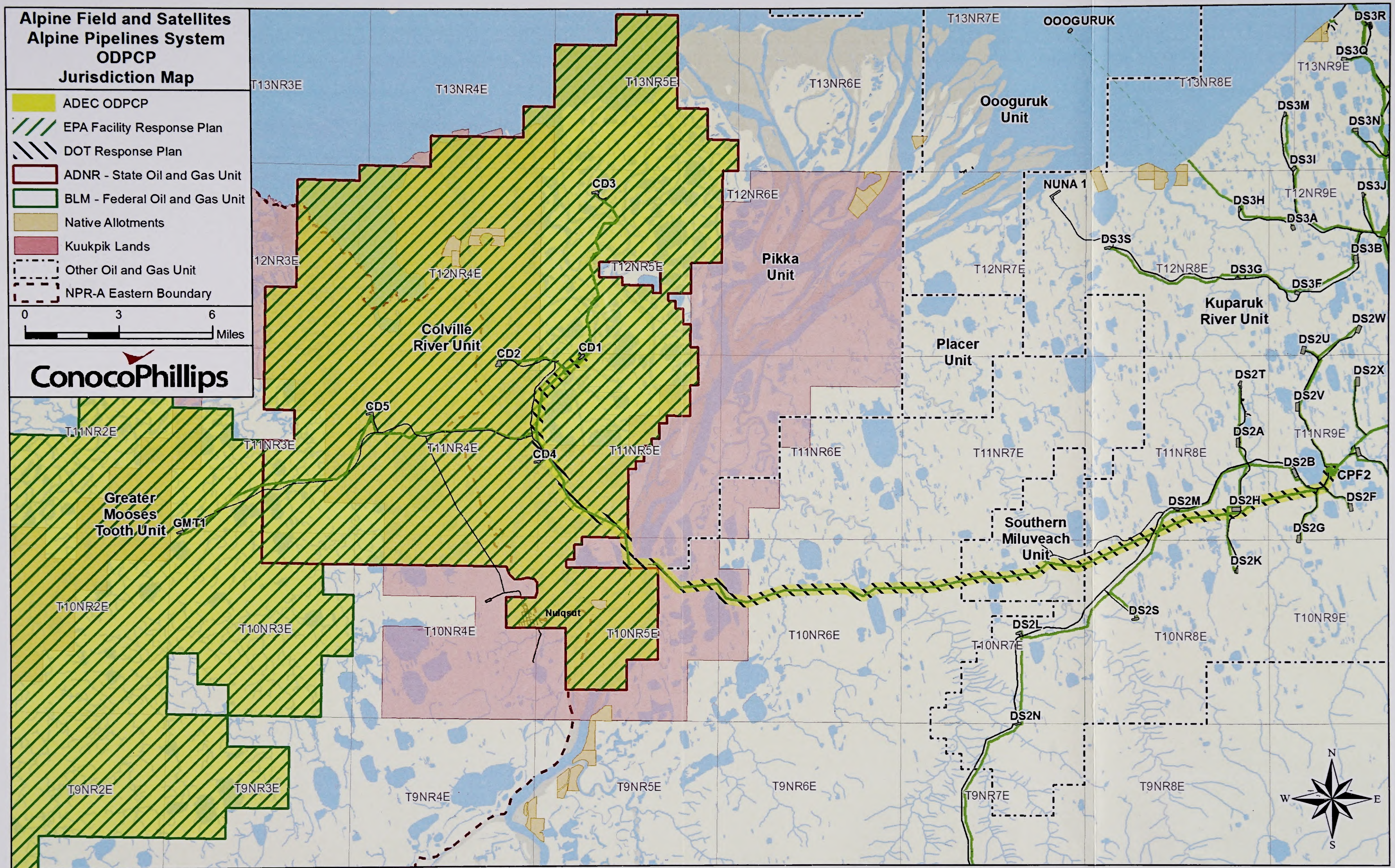
Revisions to the ODPCP are documented in the Record of Revisions. Upon request, hard copies of changed pages or electronic copies are distributed to plan recipients, including regulatory agencies and emergency operations centers. Upon receipt of revisions, the plan recipient replaces pages (hardcopy) or the previous disc, as instructed. It is the responsibility of each plan recipient to ensure updates are promptly addressed.

COPA ensures that plan renewals are submitted to the appropriate agencies according to their renewal timeframe. The approvals covered by this ODPCP and relevant renewal cycles are listed below:

| Regulating Agency | Renewal Cycle | Expiration Date |
|---|---|---|
| ADEC | 5 years | February 15, 2023 |
| EPA | No more than every 5 years for facility response plan | December 12, 2022 |
| DOT | 5 years | September 11, 2022 |

BLM requirements do not specify a plan review and/or renewal cycle. At a minimum, the plan is available to BLM as part of the ADEC 5-year renewal process.

BLANK PAGE


Alpine Field and Satellites
Alpine Pipelines System
ODPCP
Jurisdiction Map
ADEC ODPCP
EPA Facility Response Plan
DOT Response Plan
ADNR - State Oil and Gas Unit
BLM - Federal Oil and Gas Unit
Native Allotments
Kuukpik Lands
Other Oil and Gas Unit
NPR-A Eastern Boundary
0 3 6 Miles
ConocoPhillips
Colville River Unit
Greater Mooses Tooth Unit
Pikka Unit
Oooguruk Unit
Placer Unit
Southern Miluveach Unit
Kuparuk River Unit
OOOGURUK
NUNA 1
CD1
CD2
CD3
CD4
CD5
GMT1
Nuiqsut
CPF2
DS3R
DS3Q
DS3M
DS3N
DS3I
DS3J
DS3H
DS3A
DS3S
DS3B
DS3G
DS3F
DS2W
DS2U
DS2X
DS2T
DS2V
DS2A
DS2B
DS2F
DS2M
DS2H
DS2G
DS2K
DS2S
DS2L
DS2N
T13NR3E
T13NR4E
T13NR5E
T13NR6E
T13NR7E
T13NR8E
T13NR9E
12NR3E
T12NR4E
T12NR5E
T12NR6E
T12NR7E
T12NR8E
T12NR9E
T11NR2E
T11NR3E
T11NR4E
T11NR5E
T11NR6E
T11NR7E
T11NR8E
T11NR9E
T10NR2E
T10NR3E
T10NR4E
T10NR5E
T10NR6E
T10NR7E
T10NR8E
T10NR9E
T9NR2E
T9NR3E
T9NR4E
T9NR5E
T9NR6E
T9NR7E
T9NR8E
N
S
E
W

# PART 1 RESPONSE ACTION PLAN [18 AAC 75.425(e)(1)]

## 1.1 EMERGENCY ACTION CHECKLIST [18 AAC 75.425(e)(1)(A)]

The person reporting an oil spill may be required to supply minimum spill assessment information to provide as complete an understanding of the event as possible. Table 1-1 provides some emergency actions and information that may be reported and Figure 1-1 provides a flow chart of steps for immediate spill notification.

### TABLE 1-1: EMERGENCY ACTION CHECKLIST

| INITIAL SPILL RESPONSE ACTIONS | WHAT TO REPORT TO YOUR SUPERVISOR |
|---|---|
| 1. Protect people: Safety is first priority.<br>• Shut off ignition sources.<br>• Restrict access.<br>• Evaluate as necessary, and initiate rescue and response actions.<br>• Evacuate nonessential personnel.<br>2. Notify Supervisor and Security.<br>3. Stop or contain the spill at source, if safe to do so.<br>4. Assess possible hazards:<br>• Fire and explosion potential of vapors at or near the source,<br>• Potential toxic effects of the discharge,<br>• Damage to facility affecting safety, and<br>• Recovery of the spilled product.<br>5. For a blowout, implement well control and evacuation procedures, and activate Tier III Incident Command System. | 1. Was anyone hurt?<br>2. Where is the spill?<br>3. What time did it happen?<br>4. What was spilled?<br>5. How much was spilled?<br>6. What is the rate of release?<br>7. What is the source?<br>8. What are the weather conditions?<br>9. What actions have you taken?<br>10. What equipment do you need?<br>11. Are there any immediate environmental impacts?<br>12. Who did you notify? |

The emergency actions and notification sequence varies depending on the size of the spill and safety issues present. A minor spill defines a situation where on-site employees do not require assistance from the Alpine Spill Response Team (SRT), or the situation does not represent an emergency. Emergency situations exist where any of these conditions are present:

- The safety of personnel is threatened.
- The spilled material is of an unknown nature and is potentially hazardous or toxic.
- The release of product cannot be quickly stopped or contained.

The levels described below apply only to the emergency phases of containment and initial recovery of a spill.

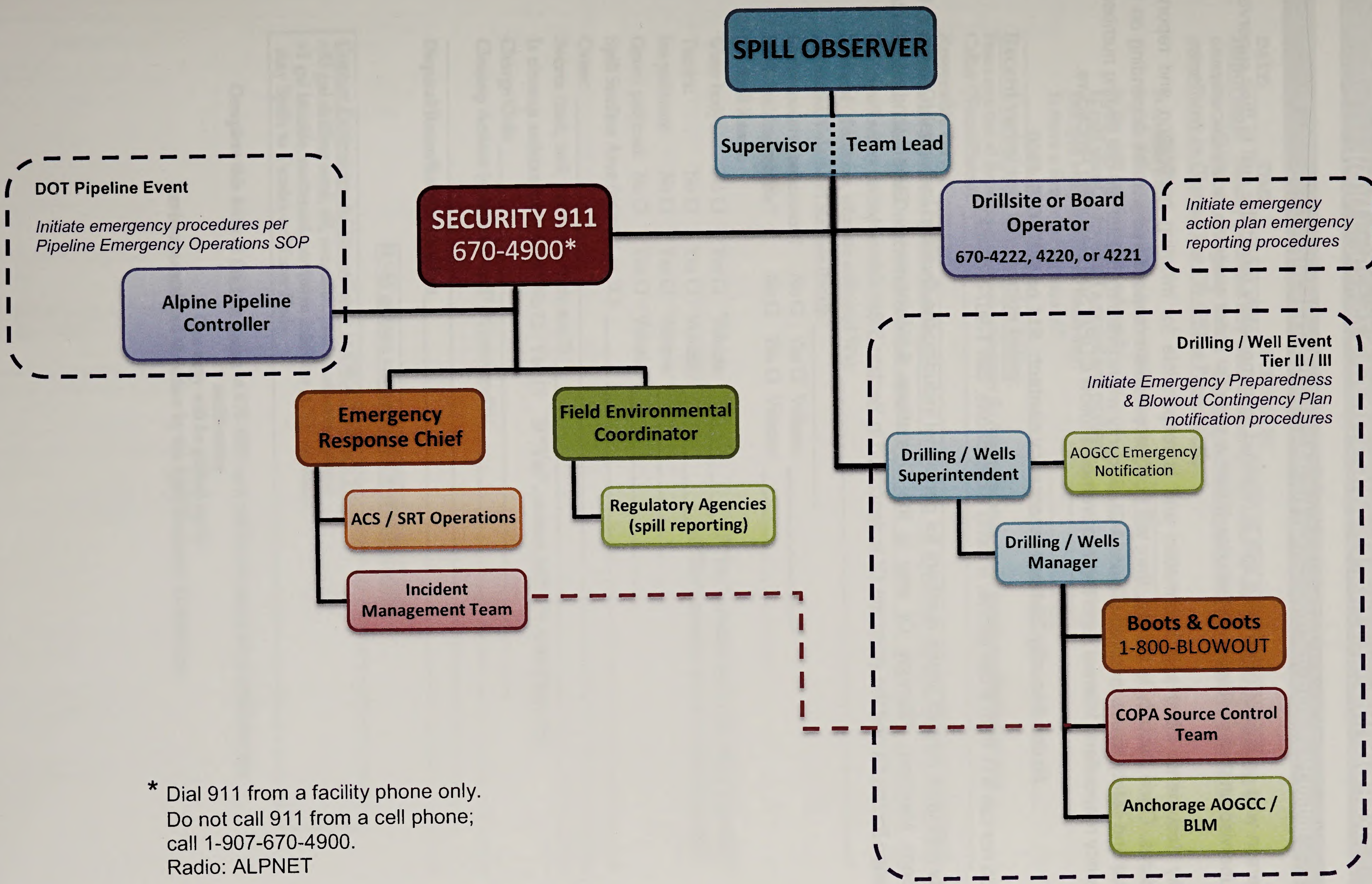
**Minor.** Defines a situation where the on-site personnel can control the incident and SRT response is not required.

**Tier I.** Defines a situation where on-site employees require immediate assistance of the on-site ACS Spill Technician(s) and, if necessary, SRT to control, contain, and cleanup a spill.

**Tier II.** Defines a situation that requires call-out of the Alpine SRT and/or Hazardous Materials (HAZMAT) Team (a Tier I response), and other resources available on the North Slope, including ACS Base resources (Deadhorse) and/or Mutual Aid.

**Tier III.** Defines a situation that requires activation of North Slope resources (a Tier II response) and those available from sources other than North Slope suppliers. A Tier III response is activated in the event of a catastrophic spill and involves use of various trained response contractors.

## FIGURE 1-1: IMMEDIATE SPILL NOTIFICATION PROCESS




* Dial 911 from a facility phone only.
Do not call 911 from a cell phone;
call 1-907-670-4900.
Radio: ALPNET

## 1.2 REPORTING AND NOTIFICATION [18 AAC 75.425(e)(1)(B)]

### 1.2.1 Initial Reporting and Notification [18 AAC 75.425(e)(1)(B)(i)]

Any person who causes or observes a spill is required to immediately report the spill to their supervisor. The supervisor makes notification to Security. If their supervisor is not available, notify Security.

Security documents initial spill information and is responsible for initiating notification and reporting procedures. Once Security is alerted, they will notify appropriate response personnel, depending on the spill size and safety issues involved (Figure 1-2). Security will activate a singular, all-call paging number to emergency responders. Internal reporting requirements follow COPA *Spill Reporting Procedure.*

**Alpine Security 24-hour emergency contact: 911 or (907) 670-4900**

Note: do not call 911 from a cell phone. If using a cell phone, call 1-907-670-4900.

Security maintains contact phone numbers for personnel including the Qualified Individual (QI) who is the Operations Manager, Alternate QI who is the Operations & Maintenance Superintendent. Contact information for the QI and the Alternate QI is described in Section 3.3.

## FIGURE 1-2: SPILL REPORT NOTIFICATION

# Alpine Spill Report Notification

**DATE:**________ **TIME:**____________ **RECEIVED BY** ________________________

**Important:** Security personnel may need to interrupt the caller to ask the following questions to determine whether an **emergency** exists. **Contact the Emergency Services Assistant Fire Chief immediately on Channel 1 or 670-4752 or Pager 601 if:**

**Is anyone hurt?** ____________
**Is this a line rupture, blowout, or corrosion leak?** ____________
**Is the spill continuing to release?** ____________
**Is spill about to travel off a gravel pad or road?** ____________
**Did spill reach a river or waterway?** ____________
**Is there a fire or safety hazard?** ____________

**Record verbal spill information below:**

Please note that all the information below is necessary for Agency reporting, please provide complete information.

**Caller (Name/Phone):** ________________________

**Responsible Party (Company):** ________________________

**Responsible Supervisor (Name/Phone):** ________________________

**Date and Time Spill Occurred** (or was first observed):________________________

**Location/Facility** (include module #s.): ________________________

**Material** (if mixture, what are estimated %'s): ________________________

**Estimated Volume of Release (total):** ____________

Into secondary containment? No ☐ Yes ☐ Volume: ____________

Inside building/module? No ☐ Yes ☐ Volume: ____________

**Did Spill Reach:**

Water body: No ☐ Yes ☐ Volume: ____________ **If "Yes", contact ACS 670-4586/Pager 602**

Tundra: No ☐ Yes ☐ Volume: ____________ **If "Yes", contact ACS 670-4586/Pager 602**

Ice pad/road: No ☐ Yes ☐ Volume: ____________

Gravel pad/road: No ☐ Yes ☐ Volume: ____________

**Spill Surface Area** (estimate sq. ft.): ________________________

**Cause:** ________________________

**Source** (tank, well, pipeline, vehicle nos.?): ________________________

**Is cleanup assistance required?** No ☐ Yes ☐ **If "Yes", contact ACS 670-4586/Pager 602**

**Charge Code** ________________________

**Cleanup Actions** (equipment used? % recovered?) ________________________

**Disposal/Reuse/Recycle Location**________________________

**If >55 gallons, contact ACS 670-4586/Pager 602**

**Contact Environmental Immediately at 670-4423/Pager 719 if:**
**>55 gal drilling mud, oil, seawater, produced water, glycol**
**>1 gal biocide, methanol, corrosion inhibitor, CTE enhancer**
**Any Spills to Tundra or Water Body**

**Complete this form & fax two copies to 670-4507 and call Environmental at x4423 for fax notification.**
**One copy will be picked up by Environmental and the other by the Spill Response Technicians.**

### 1.2.2 External Reporting and Notification [18 AAC 75.425(e)(1)(B)(ii)]

The Field Environmental Coordinator is responsible for notifying the appropriate regulatory agencies and landowners, in accordance with COPA *Spill Reporting Procedure*.

Federal law requires that at least one of its representative agencies be notified of qualifying spills of oil or hazardous substances. Federal law also requires that the National Response Center (NRC) be notified of all hazardous substance spills that exceed the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) reportable quantity limit. This notification should be made within two hours of the incident.

For incidents on federal lands, BLM requires verbal notification of major undesirable events, including spills, as soon as possible; but no later than 24 hours after the event.

At the earliest practicable moment following discovery, but no later than one hour after confirmed discovery, DOT requires notification of spills from the Alpine crude oil and diesel pipelines that involve one or more of the following conditions:

- Explosions or fires,
- Death or personal injury requiring hospitalization,
- Estimated damage to property of $50,000 or more, or
- Pollution of any body of water.

DOT requires information on weather conditions for any reported spill. During severe flooding conditions, COPA provides open communications with local and state officials to address concerns regarding observed environmental conditions that may affect the integrity of pipeline crossings. A telephone report made more than two hours after confirmation of a reportable condition is considered late.

Primary agency reporting requirements are provided in Table 1-2. As appropriate per regulatory requirements and/or operating agreements, verbal notifications and/or written reports are provided to:

- National Response Center (EPA, DOT, and U.S. Coast Guard);
- U.S. Department of the Interior, Bureau of Land Management;
- Alaska Department of Environmental Conservation
- Alaska Department of Fish & Game
- Alaska Department of Natural Resources
- Alaska Oil and Gas Conservation Commission
- North Slope Borough
- Kuukpik Corporation

# TABLE 1-2: AGENCY REPORTING REQUIREMENTS FOR OIL SPILLS AND HAZARDOUS MATERIALS

| AGENCY | LOCATION / RECEIVING ENVIRONMENT | SPILL SIZE | VERBAL REPORT | PHONE NUMBER | WRITTEN REPORT |
|---|---|---|---|---|---|
| National Response Center EPA, DOT, and USCG | Into or upon navigable waters of the U.S. or to land that may threaten navigable waters of the U.S. | Any | **Immediately** | (800) 424-8802 (24 hour)<br><br>Note: DOT requires notification at the earliest practicable moment following discovery, but no later than one hour after confirmed discovery. Follow up is required within 48 hours. | Form completed during phone notification.<br>For SPCC facilities, if spill is ≥1,000 gallons or if it is a second spill >42 gallons in 12 months to water or tundra, submit written report to EPA. |
| ADEC<br><br>ADNR (same requirements as ADEC)<br><br>*ADF&G (any release to fish-bearing waters)*<br><br>*Kuukpik Corporation (within Kuukpik withdrawal area or if IMT activated)* | Off pad to water or tundra | Any | Immediately (within 30 minutes) | ADEC<br>(907) 451-2121<br>(907) 451-2362 (fax)<br>or<br>AK State Troopers<br>(after hours and weekends)<br>(800) 478-9300<br><br>ADNR<br>(907) 451-2719<br>dnr.nro.spill@alaska.gov<br>ADF&G - Fairbanks<br>(907) 459-7289<br>(907) 459-7303<br>Kuukpik<br>(907) 480-6220<br>(907) 480-6126 (fax) | Submit within 15 days after containment and cleanup are completed or, if no cleanup occurs, within 15 days after the discharge or release. |
| | On gravel pad, gravel road, ice pad, ice road, or snow-covered tundra | 1 to 10 gallons (<1 gallon no report) | Monthly written report | | |
| | | >10 to 55 gallons | Within 48 hours | | |
| | | >55 gallons | Immediately | | |
| | Into impermeable secondary containment area or structure | >55 gallons | Within 48 hours | | |
| Alaska Oil and Gas Conservation Commission (AOGCC) | Well release (crude or gas) | Any | Immediately | Anchorage<br>(907) 279-1433<br>(907) 276-7542 (fax)<br><br>North Slope (Field)<br>(907) 659-2714<br>(907) 659-3607 (pager)<br>(907) 659-2717 (fax) | Submit within 5 days of loss; final report required within 30 days. |
| North Slope Borough (NSB) | Off pad to water or tundra | Any | Immediately | Permitting & Zoning<br>(907) 301-1461<br>(907) 852-0321 (fax)<br><br>LEPC - Risk Management<br>(907) 852-0248<br>(907) 852-0356 (fax) | Submit within 7 days. |
| | On gravel pad, gravel road, ice pad, ice road, or snow-covered tundra | >55 gallons | Immediately | | |
| | Into impermeable secondary containment area or structure | >55 gallons | Within 48 hours | | |
| State Pipeline Coordinator's Section (SPCS)<br><br>U.S. Department of Transportation (DOT) | From pipeline administered by the SPCS or to pipeline ROW | Any | Immediately | SPCS<br>(907) 269-6403<br>(907) 269-6880 (fax)<br>NRC<br>(800) 424-8802 (24 hour)<br>DOT - Anchorage<br>(907) 271-6519 or 271-6517 | Submit DOT Form 7000-l within 30 days (see form for details). |
| | From DOT-regulated pipeline | ≥5 gallons | | | |
| Bureau of Land Management (BLM) | Major Undesirable Events – all spills or releases of petroleum fluids or chemicals used in the petroleum industry | Any | As soon as practicable, but no later than 24 hours | Anchorage<br>(907) 267-1446<br>(907) 276-1304 (fax)<br><br>Fairbanks<br>(907) 474-2301<br>(907) 474-2307 (Hazmat)<br>(907) 474-2386 (fax) | Submit in duplicate within 15 days after the incident |

## 1.3 SAFETY [18 AAC 75.425(e)(1)(C)]

At COPA, our work is never so urgent or important that we cannot take the time to do it safely and in an environmentally prudent manner. The COPA *Alaska Workforce HSE Roles & Responsibilities* handbook defines specific Health, Safety, and Environment (HSE) roles, responsibilities, and performance criteria designed to achieve the goal of zero incidents, injuries and illnesses, and promote COPA Incident-Free Culture. In addition, the *Alaska Safety Handbook* presents "best" safety procedures and standards to guide employees and contractors working at COPA facilities on the North Slope. Workers are expected to understand and use the safety rules presented in the handbook as a requirement of employment. The handbook is made available to COPA employees and contractors.

The steps necessary to develop an incident-specific safety plan for conducting a response are outlined in the ACS *Technical Manual*, Tactics S-1 to S-6. The ACS tactics, incorporated here by reference, include site entry procedures, site safety plan development (Incident Command System [ICS] Form 201-5), and personnel protection procedures.

Safety procedures and emergency action plans are made available to employees and contractors on the COPA intranet. At the time of an incident, an incident-specific safety plan is developed by the Incident Management Team (IMT), which documents initial assessment and response plan recommendations.

As outlined in the North Slope Sub-Area Plan, the Local On-Scene Coordinator (LOSC) will be involved in any spill that poses an immediate threat to public safety. The North Slope Borough LOSC, or designee, will typically integrate into the incident command system through a liaison representing all affected communities.

## 1.4 COMMUNICATIONS [18 AAC 75.425(e)(1)(D)]

The spill communication system supports the organizational structure of spill response efforts and is scalable in both size and scope to serve both small- and large-scale response events. An event that is limited to a local response by the SRT is adequately served by the local SRT communications system. An event that invokes a response by ACS or involves a significant Mutual Aid effort with other North Slope operators is able to use ACS communications equipment and upgrade smoothly from the local communication system to the ACS wide-area communications system.

The Alpine communication resources available for spill response may be loosely classified into the following four categories:

1. **COPA SRT Telecom Resource**: Communication resources designed to support spill response and developed for the SRT and the COPA Incident Command Post.
2. **ACS Telecom Resource**: Communication resources that are part of the ACS Telecommunications Plan. These resources are available for COPA and members of ACS.
3. **North Slope Telecom Resource**: Communication resources t not designed exclusively for spill response but may directly or indirectly play an important supportive role toward a successful response effort.
4. Locally available public resources (cellular service).

During an incident, the Communications Unit Leader in the IMT will provide the most effective communications system necessary to support the response actions of the SRT, and will develop a communications plan to suit the response.

A detailed explanation of oil spill response communications on the North Slope is provided in the ACS *Technical Manual,* Volume 1, Tactic L-5.

Communications in the Alpine area are currently provided by a digital Microwave system that extends the COP Network to these locations. This Network provides IP Phones and the Computing capabilities. This Microwave system also extends the Digital two-way radio system that connects Alpine and Kuparuk. This Microwave extension has also provided the ability to provide a remote portable Cellular site that extends ASTAC & AT&T services into the NPR-A. COPA also has available, a ground-based satellite system as backup.

COPA installs a VHF repeater at each remote site with the correct ACS frequencies to provide extended local coverage for spill response personnel using hand held and mobile radios during a response. The extension of the COPA Microwave Network into remote areas is provided through a series of statically installed temporary towers varying in size, depending on project needs.

North Slope personnel may have on-site, the following additional equipment:

- Cell phones
- Portable satellite phones
- Hand held and mobile radios for on-site use and area-wide communications

Oil Spill Response repeaters installed across the North Slope provide response radio coverage from eastern NPR-A to Badami. The range of each fixed repeater is approximately 30 to 50 miles, depending on topography.

Of the areas covered by this ODPCP, the NPR-A area is the most remote, and therefore poses the greatest communications challenges. Oil spill response communications in NPR-A will initially use VHF radios. The Alpine operating area has a 115-ft. radio tower, and a VHF repeater at the Alpine Base will provide communications throughout the Alpine operating area. This repeater is tied into the ACS wide-area VHF radio network as Channel OS-33.

The oil spill response communications frequencies assigned to Alpine are as follows:

VHF Oil Spill (OS-33)

- Repeater Transmit: 159.585 MHz
- Repeater Receive: 161.235 MHz
- Private Line Code 103.5 Hz

Communications within the boundaries of the Kuparuk River Unit have access to the Kuparuk area VHF radio system. The frequencies assigned to Kuparuk are as follows:

VHF Oil Spill (OS-35)

- Repeater Transmit: 154.585 MHz
- Repeater Receive: 150.980 MHz
- Private Line Code 107.2 Hz

## 1.5 DEPLOYMENT STRATEGIES [18 AAC 75.425(e)(1)(E)]

### 1.5.1 Transport Procedures [18 AAC 75.425(e)(1)(E)(i)]

COPA daily operations provide an infrastructure for a spill response. The extensive transportation infrastructure for personnel and equipment can support a small response and can be enhanced for a major spill. Existing access to channels in the Colville River delta is currently provided by the CD1 boat launch in the Sakoonang Channel. Infrastructure and pre-staged equipment is described in ACS *Technical Manual*, Volume 2, Map Atlas Sheets 8, 9, 12, 16, 17, 18, 20, 21, 22, 23, 23A, 24, 25, 26, 27, 121, 125, and 126.

Transportation options, depending on the location, season, availability, and weather, include vessels, road vehicles, tundra travel vehicles, helicopters, fixed-wing planes, and air-cushion vehicles. Ice roads may also be constructed to provide site access during the winter. Table 1-3 summarizes Alpine's seasonal transportation options.

**TABLE 1-3: SEASONAL TRANSPORTATION OPTIONS**

| MODES OF TRANSPORTATION | SUMMER | WINTER | BREAK-UP / FREEZE-UP |
|---|---|---|---|
| Vessel | X | | |
| Helicopter | X | X | X |
| Fixed-wing aircraft | X | X | X |
| Road vehicle | X[1] | X | X[1] |
| Tundra travel vehicle | X | X | X |
| Air-cushion vehicle | X | X | X |

[1]Travel between CD1 and satellite drill sites, excluding CD3

The estimated response time from discovery of a spill to the deployment of equipment varies depending on the location, pre-planning, logistical support, and available information. For planning purposes, 5 knots is used for vessels; 100 miles per hour (mph) for helicopters; 150 mph for light, fixed-wing aircraft; 300 mph for heavy, fixed-wing aircraft; 5 mph for tundra travel vehicle transport across tundra; and 35 mph for road vehicles. Table 1-4 describes the estimated response times for Alpine.

**TABLE 1-4: ESTIMATED RESPONSE TIME**

| RESPONSE | TIME |
|---|---|
| Immediate response | Immediate response will occur with the pre-staged response equipment. |
| Aircraft<br>(Mobilization is 1 hour from notice to fly.) | Aircraft from Deadhorse within 2 hours.<br>Light fixed-wing aircraft from Deadhorse is 30 minutes.<br>Light fixed-wing aircraft from Kuparuk is 15 minutes (good weather). |
| Vehicle | CD1 to CD3 (winter ice road) – 10 to 15 minutes.<br>CD1 to road-based satellite drill sites – varies; up to 1 hour (see maps in Section 1.8 for distances). |
| Initial SRT response along pipeline route | Alpine Pipeline route - within 2 hours. |
| Vessel<br>(Oliktok Dock to Colville River Delta) | 2.2 hours after the vessel is underway.<br>(vessels response time from CD1 varies) |
| Tundra travel vehicle | From Kuparuk or Deadhorse – varies<br>CD1 to CD3 – 1.2 hours. |

During the summer, travel to CD3 is possible by aircraft or boat; travel times will vary based on aircraft or vessel origin. Estimated times for transportation of containment, exclusion, and recovery equipment from

the Prudhoe Bay and Deadhorse areas to Nuiqsut and/or Alpine are summarized in Tactics L-3 and L-4 in the ACS *Technical Manual*. Response times will vary depending on the location and the time of year that a spill occurs. These variables are discussed for each site-specific scenario provided in Section 1.6.3. Rolligons have the capability to float on water and may cross channels in shallow water (≤2 feet) or may float until reaching a shallow area, if conditions are safe. Use of Rolligons or other vehicles for tundra travel during all seasons requires authorization by ADNR and may be subject to other approval requirements from local or federal jurisdictional agencies.

SRT airboat operators are trained to navigate the channels of the Colville River delta. In addition, channels are surveyed and navigation markers are deployed each summer to assist spill responders traveling through the delta channels.

### 1.5.2 Notification and Mobilization of Response Action Contractor [18 AAC 75.425(e)(1)(E)(ii)]

Section 1.1 describes immediate response and notification actions, which may include notification of ACS. While ACS is mobilizing personnel and equipment to the spill site, COPA personnel determine safety procedures, notify government agencies and COPA personnel, and proceed with source control measures. In addition, if safe to do so, COPA response personnel will deploy on-site spill containment equipment.

ACS is the primary response action contractor for COPA. The 24-hour phone number for ACS is listed in Section 3.8. The on-site personnel are the initial responders to spills at Alpine. SRT members promptly respond upon notification. Equipment will be deployed in the manner appropriate to the type of spill, based on tactics established in the ACS *Technical Manual*. Pre-staged and pre-deployed oil spill response equipment is discussed in Section 3.6.

## 1.6 RESPONSE SCENARIOS AND STRATEGIES [18 AAC 75.425(e)(1)(F), 18 AAC 75.425(e)(1)(I), AND 18 AAC 75.445(d)]

### 1.6.1 Qualifier Statement

The scenarios and response strategies described in this plan were developed according to 18 AAC 75.425(e)(1)(F) and (I). They describe general procedures, equipment, personnel, tactics, and operational capabilities that could be used to respond to an oil spill using applicable response strategies required by 18 AAC 75.425(e)(1)(F)(i) through (xii) and 18 AAC 75.445(d).

These scenarios are for illustration only and are not performance standards or guarantees of performance. The scenarios assume potential conditions of the spills and responses to demonstrate COPA's capability to respond to a discharge of each applicable response planning standard (RPS) volume within the required timeframes using the resources described in this ODPCP and as required by 18 AAC 75.425(e)(1)(F) and (I). The RPS volume calculations are presented in Part 5.

The scenarios identify the location, time of year, time of day, source and cause of spill, quantity and type of oil spilled, relevant environmental conditions (including weather, sea state, and visibility), spill trajectory, expected timeline for response actions, and a description of response actions to be taken. The response scenarios and strategies are usable as a general guide for a discharge of any size, and describe the discharge containment, control, and cleanup actions to be taken, which demonstrate the strategies and procedures adopted to conduct and maintain an effective response. Well blowout scenarios include a summary of planned methods, equipment, logistics, and timeframes proposed to be employed to control a well blowout within 15 days. The response strategies illustrate specific response measures that can reduce the risk, magnitude, or environmental impact of an oil spill, considering the variation of receiving environments and seasonal conditions. The response strategies address each of the relevant required elements of 18 AAC 75.425(e)(1)(F)(i) through (xii).

Some details in the scenarios and response strategies are for illustration purposes; and although some equipment is named, it may be replaced by functionally similar equipment. These details do not limit the discretion of the persons in charge of the spill response to select any sequence or take whatever time they deem necessary to respond to a spill without jeopardizing personnel safety.

In situ burning could be used in a spill response to reduce the quantity of oil, regardless of whether a scenario hypothesizes in situ burning to help meet the RPS.

Actual responses in an oil spill emergency depend on personnel safety considerations, weather, other environmental conditions, agency permits and priorities, and other factors. In any incident, considerations to ensure the safety of personnel will be given highest priority. If severe weather or other conditions limit the safety of personnel, COPA may take precautions up to and including suspending response efforts until it is deemed safe to proceed. Likewise, if operating limitations are reached because of weather conditions, COPA will reassess the response effort and take necessary precautions to protect personnel and equipment. The scenarios assume the agency on-scene coordinators and other agency officials will immediately grant any required permits.

### 1.6.2 Temporary Storage and Disposal [18 AAC 75.425(e)(1)(F)(x)]

Temporary storage of oil, oily waste, and debris recovered during a spill cleanup may be provided by tanks, pits, or basins located at facilities near the site. The spill location or other logistical concerns may require

storage of oil, oily waste, and debris in smaller, more portable containers that can be brought to the scene via truck, boat, or aircraft.

Other temporary storage options during a spill response include lined natural depressions, construction of lined earthen dikes, and portable storage (bladder tanks, inflatable tanks, open-top drums, vacuum trucks, dump trucks, etc.).

There are six permitted temporary solid waste cells at Pad 3 in the Prudhoe Bay Eastern Operating Area. Although it is not a permanent disposal site, long-term storage of solid hydrocarbons is possible. Requirements for use of the Pad 3 oily solid waste pits are set by ADEC solid waste disposal permit.

There are also two permitted temporary storage pits at Pad 3 – the East Pit for contaminated snow and the West Pit for contaminated gravel. Contaminated snow from the East Pit is melted each spring and injected into one of the Pad 3 Class I wells. Gravel from the West Pit is thermally remediated each summer or every other summer, depending on the volume requirements. Kuparuk DS-1H may also be used for contaminated gravel and/or snow storage, and contains 12,230 cubic yards of storage capacity. Gravel from DS-1H is thermally remediated each summer or every other summer, depending on volume requirements.

During the summer months at Alpine, when it may not be feasible to transport contaminated gravel to the Eastern Operating Area or Kuparuk, temporary storage cells would be constructed on site using appropriate liner and construction materials.

The method of disposal for oil and contaminated materials from spill recovery operations (or for oily waste from normal operations) must be approved and permitted by the appropriate state and federal agencies. At the time of the spill, the Operations Chief, in consultation with the Environmental Unit Leader, determines the reuse, recycle, or disposal method best suited to the state of the oil, the degree of contamination of recovered debris, and the logistics involved in these operations. See Tactics D-1 through D-5 in the ACS *Technical Manual*. An initial determination must be made regarding the classification of the waste as exempt, hazardous, or non-hazardous. This classification can be made on a case-by-case basis. The Environmental Unit Leader provides assistance in determining the classification if the status of the waste material is in question. In general, the following guidelines apply:

- Spills from DOT pipelines are non-exempt and may need to be tested to determine whether the material to be disposed of is hazardous.
- Spills from production lines are exempt.
- Spilled material that comes out of a well, either during drilling or work-over operations, is exempt. Spilled material that did not come out of a well is non-exempt and may need to be tested to determine if the material to be disposed of is hazardous.
- Spills that occur from filling a tank (i.e., vehicle, storage, etc.) are non-exempt, even though they may occur on a well pad; product knowledge or testing may be needed to determine if the material to be disposed of is hazardous.

The preferred management option for recovered oil is to recycle it back into the production stream via existing oil production facilities at Alpine CD1. Should materials need to be transported off the North Slope for handling and disposal by a third-party hazardous waste management contractor, truck, barge, and/or air transportation would be arranged. Guidelines for handling and managing oil and contaminated materials or oily waste are found in the *Alaska Waste Disposal and Reuse Guide* also known as the “Red Book”.

### 1.6.3 Response Scenarios and Strategies [18 AAC 75.425(e)(1)(F) and (I)]

The following response scenarios and response strategies are included in this section:

- **Scenario 1:** Well Blowout in Summer
- **Scenario 2:** Well Blowout in Winter
- **Scenario 3:** Alpine Pipeline Release to the Miluveach River in Summer
- **Scenario 4:** Alpine Tank Rupture in Summer

BLANK PAGE

# SCENARIO 1

# WELL BLOWOUT IN SUMMER

**BLANK PAGE**

## TABLE 1-5: WELL BLOWOUT IN SUMMER - TYPICAL ENVIRONMENTAL CONDITIONS

| | |
|---|---|
| **Spill Location** | Production well CD5-313 on Alpine CD5 Pad |
| **Date / Time** | August 1 / 0800 |
| **Duration** | 15 days |
| **Source of Spill** | Although production wells are secured with a wellhead or blowout preventer while drilling, and are enclosed, this scenario assumes an uncontrolled well blowout occurs through an unobstructed open orifice. |
| **Cause of Spill** | Underbalanced well and failure of pressure control systems. |
| **Quantity of Oil Spilled** | RPS Volume: 150,000 barrels<br>Based on a maximum production rate of 10,000 bopd and a blowout duration of 15 days. |
| **Emulsification Factor** | 1.67 (Applicable to oil that reaches open water, for storage purposes.) |
| **Oil Type** | North Slope Alpine Crude |
| **Wind Speed** | Average August wind speed is 22 mph |
| **Wind Direction** | The predominant wind directions are ENE, NE, E, and W (see Figure 1-3). The winds blow from the ENE 40% of the time (6 days) and from the other directions, 20% of the time (3 days each):<br>• Days 1 through 6: wind from ENE<br>• Days 7 through 9: wind from NE<br>• Days 10 through 12: wind from W<br>• Days 13 through 15: wind from E |
| **Current** | Low. Oil falls to nearby lakes and may impact ephemeral or low flow streams. |
| **Air Temperature** | 51 degrees Fahrenheit (°F) |
| **Surface** | Well is on a gravel pad located approximately 4 miles west of the Nigliq Channel, and approximately 8 miles west of CD1. Surrounding surface is tundra and tundra lakes and interconnecting streams. |
| **Trajectory** | The simulated blowout discharges at a rate of 10,000 bopd with a GOR of 650 scf/bbl.<br>The SL Ross oil deposition model provided in ACS *Technical Manual* Tactic T-6 projects that the oil takes the form of an aerial plume extending from the well in the direction of the predominant wind directions. The blowout discharges 150,000 barrels of oil to the WSW, SW, W, and E of well CD5-313 (Figure 1-4). The model predicts the following plume dimensions:<br>• 70% of the discharged oil falls within 430 feet downwind of the well. At that distance, the plume is about 90 feet wide.<br>• 80% of the discharged oil falls within 1,275 feet downwind of the well. At that distance, the plume is about 235 feet wide.<br>• 90% of the discharged oil falls within 8,885 feet (1.7 mile) downwind of the well. At that distance, the plume is about 1,355 feet wide.<br>• According to the SL Ross model, 10% of discharged oil is in the form of droplets so small (50 micrometers or less) that they do not fall to the ground.<br>Under the SL Ross model, approximately 70% (105,000 barrels) of the discharged oil falls on the CD5 pad. Not all oil falling on the pad is retained by gravel. If not recovered, discharged oil accumulates in low-lying areas and eventually flows off the pad. Approximately 30,000 barrels of oil falls beyond the pad. An estimated 4,300 barrels enters open water. The average thickness of the oil deposited on water surfaces is 0.10 inch. |

## TABLE 1-6: WELL BLOWOUT IN SUMMER - RESPONSE STRATEGY

<table>
<tr><th>ADEC REQUIREMENT</th><th>RESPONSE STRATEGY</th><th>ACS TECHNICAL MANUAL TACTIC</th></tr>
<tr><td>(i) Stopping Discharge at Source</td><td>Efforts are made to bring the well under control. Emergency shutdown procedures are initiated.<br>Once it has been determined that control of the well cannot be immediately regained, or the safety of personnel is at risk, personnel are evacuated to the pre-designated safe area. At all times, the safety of personnel is COPA's first concern. No unauthorized personnel are allowed near the spill area.<br>The Drilling/Wells Supervisor notifies the Drilling/Wells Superintendent. All appropriate notifications are made according to the COPA Drilling & Wells Emergency Preparedness & Blowout Contingency Plan.<br>Boots & Coots is activated and dispatched from Houston, Texas within 12 hours.<br>The COPA IMT is activated; the Source Control team develops a well control strategy and coordinates logistics for mobilizing well capping resources.<br>Boots & Coots initiates plans to cap the well.<br>The blowout is controlled on Day 15.</td><td></td></tr>
<tr><td>(ii) Preventing or Controlling Fire Hazards</td><td>Throughout the first few hours of the spill, the Site Safety Officer verifies that all sources of ignition are shutdown or removed from the area. The Site Safety Officer provides access zone information and determines personal protective equipment (PPE) requirements. Access to the spill site is carefully controlled and the scene is secured by Security. Monitoring protocol is established by the Site Safety Officer for all work areas to ensure personnel protection. No personnel are allowed in the hot zones unless proper PPE is worn and it is permitted by the Site Safety Officer.<br>Containment and recovery operations are allowed without respiratory protection in areas where safety criteria are met. Recovery operations and traffic are not allowed downwind of the blowout well in areas where workers may become exposed to flash fire hazard or to oil particulate matter at concentrations in excess of permissible exposure limits. Firewater coverage is set up.</td><td>S-1<br>through<br>S-6</td></tr>
<tr><td>(iv) Surveillance and Tracking of Oil on Open Water; Forecasting Shoreline Contact Points</td><td>Blowout plume model is run. Aerial surveillance of oiled tundra and water is visually conducted by helicopter and by FLIR mounted on small fixed-wing aircraft. Initial estimates are made as to volume of spilled oil.</td><td>T-6<br>T-2, T-4, T-5, T-7</td></tr>
<tr><td>(v) Protection of Environmentally Sensitive Areas</td><td>No ACS priority protection sites occur within the projected oil plumes impact area or vicinity.<br>The nearest priority protection sites are located at the mouth of Fish Creek, approximately 3.5 miles north of the blowout well. A Sensitive Area Protection Task Force is deployed to the following priority protection sites:<br><table><tr><th>Priority Site #</th><th>Map Atlas</th><th>Boom Required (ft)</th><th>Tactic</th></tr><tr><td>34</td><td>7</td><td>600</td><td>C-14</td></tr><tr><td>35</td><td>7</td><td>500</td><td>C-14</td></tr><tr><td>36</td><td>7</td><td>1,000</td><td>C-14</td></tr><tr><td>37</td><td>7</td><td>300</td><td>C-14</td></tr><tr><td>38</td><td>6</td><td>300</td><td>C-14</td></tr><tr><td>39</td><td>6</td><td>300</td><td>C-14</td></tr></table>Response activities are conducted away from cultural sites, based on a cleanup plan approved by the Unified Command, in consultation with the ADNR Office of History and Archaeology (OHA).</td><td>W-6<br>C-14<br>ACS Map Atlas, Sheets 6 and 7</td></tr>
</table>

## TABLE 1-6 (CONTINUED): WELL BLOWOUT IN SUMMER - RESPONSE STRATEGY

| ADEC REQUIREMENT | RESPONSE STRATEGY | ACS TECHNICAL MANUAL TACTIC |
|---|---|---|
| **(v) Protection of Environmentally Sensitive Areas (continued)** | Pre-staged equipment and pre-deployed boom are located at numerous locations in the Alpine area (see Figure 3-3). Resources are redistributed as needed for priority protection sites and exclusion booming areas. The resources include:<br>• ALP-9 is located on the Nigliq Channel. It contains 4,350 feet of river boom, a 3-inch trash pump, a drum or brush skimmer, two anchor systems and four 2,500-gallon (59-barrel) open-top storage units.<br>• Approximately 200 feet of river boom are seasonally pre-deployed at NK-3, Nanuq Lake and 1,500 feet of river boom is storage at NK-4..<br>• Seasonal pre-deployed boom in the Sakoonang Channel consists of approximately 500 to 750 feet of river boom deployed at both SK-13 and SK-15 control sites, upstream and downstream of CD1.<br>• Three locations along the Sakoonang Channel contain response equipment. Locations ALP-5, ALP-10, and ALP-14 each contain over 1,000 feet of river boom, a 3-inch trash pump, a drum or brush skimmer, at least two anchor systems and at least four 2,500-gallon (59-barrel) open-top storage units. No oil is projected to fall in the Sakoonang Channel; consequently, all equipment is available to be re-allocated to priority protection sites and exclusion booming areas. | Pre-staged Equipment: ACS Map Atlas, Sheets 8, 9, 12, 16, 17, 20, 21, and 22 |
| **(vi) Spill Containment and Control Actions** | Upon initial reports and assessment of the blowout, ACS begins transportation of additional containment and recovery equipment from Deadhorse and other North Slope facilities to Alpine. Equipment is transported via air to a staging area at CD1. On Day 1, additional vessels are deployed from Oliktok Point or West Dock. The Alpine airstrip remains in operation to support response efforts. | L-3 |
| | COPA, in conjunction with ACS, begins obtaining the proper permits needed for spill response operations. | A-3 |
| | Crews work cross-wind or upwind of the aerial oil plume. All containment and control activities are conducted in accordance with ACS and COPA site entry protocols. | S-1 to S-6 |
| | **Pad and Tundra Containment and Control:**<br>Resources are mobilized by Day 2 to provide containment and control of oil that enters pad and tundra environments. Efforts continue throughout the blowout and after the blowout ends until oil is cleaned up. Mobilized resources are appropriate to provide sufficient containment and control to clean up the RPS volume spilled to pad and tundra surfaces. | |
| | **Task Force 1 (TF-1)** builds trenches and berms at strategic locations on and off the pad to contain oil and control its movement away from water bodies and site access points. Work conducted near the blowout is carefully monitored for safety; no ignition sources are allowed in hot zones and proper PPE is required. | C-3<br>C-4 |
| | The pad retains oil up to 0.125 barrel per cubic yard (cu yd) of gravel. The pad retains an estimated 1,370 barrels of oil over an approximate area of 98,579 square feet, assuming a depth of 3 feet. The remaining oil spreads on the surface of the pad. | R-26 |
| | **Lake Containment and Control:**<br>Resources are mobilized by Day 2 to provide containment and control of oil that enters open water environments. Efforts continue throughout the blowout and after the blowout ends until oil is cleaned up from water surfaces within 72-hours of the end of the blowout. | |
| | **Task Force 2 (TF-2)** deploys and maintains deflection and exclusion boom on lakes for collection and recovery of oil spilled on-water. | C-5 |

## TABLE 1-6 (CONTINUED): WELL BLOWOUT IN SUMMER - RESPONSE STRATEGY

| ADEC REQUIREMENT | RESPONSE STRATEGY | ACS TECHNICAL MANUAL TACTIC |
|---|---|---|
| (vii) **Spill Recovery Procedures** | Resources are mobilized by Day 2 to provide effective recovery of oil that pools on pad and tundra surfaces and that enters open water environments. Spill recovery efforts continue throughout the blowout and after the blowout ends until oil is cleaned up. Mobilized resources are sufficient to provide enough recovery capacity to cleanup an estimated 4,300 bbl spilled to open water by Day 18 (i.e., 72-hours after the blowout ends), as well as the additional RPS volume spilled to pad and tundra surfaces. Estimated recovery capacity and handling capacity indicate the RPS volume could be cleaned up in approximately 15 days under normal, continuous operations (see Table 1-7 for recovery capacity rates). | |
| | Recovery operations begin after safety protocols are established. Recovery continues for the duration of the blowout as long as conditions allow for safe operations. | S-1 to S-6 |
| | **Pad and Tundra Liquid Recovery:** | |
| | In areas on and nearby the gravel pad, where up to 80% of the oil is deposited, recovery task forces target pooled oil in berms and trenches created by TF-1 and natural depressions. | |
| | **Task Force 3 (TF-3):** TF-3 mobilizes five vacuum trucks, and associated pumps and hoses from locations within Alpine. TF-3 begins recovery of oil by direct suction from the drainage basins and the bermed and trenched areas containing oil that falls on and off the pad. If oil is encountered on water, it is recovered with a Manta Ray skimmer head. Vacuum trucks can recover liquid oil up to 200 feet from the truck. | R-6, R-7 |
| | **Task Force 4 (TF-4):** by Day 2 TF-4 mobilizes three Rolligons with 10,000-gallon tanks and trash pumps for recovery of oil by direct suction in areas on the tundra that are inaccessible by vacuum truck. The Rolligons transfer recovered oil to temporary storage tanks or vacuum truck staged along the CD5 access road. An all-terrain vacuum unit is used as needed to reach pools of oil. | R-6, R-7, R-23 |
| | **Tundra and Lake Liquid Recovery:** | |
| | **Task Force 5 (TF-5):** TF-5 uses portable skimmers and pumps to recover oil from depressions in tundra that the vacuum trucks and Rolligons cannot access. Rope mop skimmers are used to skim oil on tundra. Drum/brush skimmers are used to skim oil on lakes at collection points established and maintained by TF-2. Portable tanks or bladders are deployed with TF-5 to provide sufficient on-site storage. TF-4 provides transfer of recovered fluids from temporary storage at TF-5 sites. TF-5 targets areas outside of active oil deposition, moving equipment and adjusting number of recovery systems, as the oil plume shifts with the prevailing wind direction. | R-8, R-24<br><br>R-23 |
| | An offshore Task Force is deployed to Harrison Bay to recover any oil that may escape. No oil is encountered and no mini barge is deployed. | R-17 |
| | Once well control is achieved, recovery teams have full access to oiled tundra, water, and gravel. Task forces maximize the number of personnel and equipment to recover oil from water surface. Once the oil is recovered from the water surface, cleanup of the tundra and pad surfaces begins: | |
| | **Task Force 6 (TF-6):** TF-6 begins the process of flushing the tundra surface. Oil is recovered by hand using sorbent materials. Plywood walkways are used to minimize traffic damage to the tundra. | R-4, R-9 |
| | Upon approval through the Unified Command, a Thermal Remediation Task Force uses weed burners to remove heavily oiled vegetation. Burning is conducted so that smoke and embers do not interfere with activities occurring at downwind locations. | B-2 |

## TABLE 1-6 (CONTINUED): WELL BLOWOUT IN SUMMER - RESPONSE STRATEGY

| ADEC REQUIREMENT | RESPONSE STRATEGY | ACS TECHNICAL MANUAL TACTIC |
|---|---|---|
| **(vii) Spill Recovery Procedures (continued)** | **Pad Decontamination and Oiled Gravel Removal:**<br>**Task Force 7 (TF-7):** TF-7 works on a non-emergency basis to pressure wash oil from structures on the pad. Once the structures are cleaned, oily gravel is recovered and stored in temporary, lined stockpiles at drill sites and/or Kuukpik pad. Estimated handling capacity rates indicates the volume of impacted gravel could be excavated and transported to lined storage in 10 days. | R-21, R-26<br>D-2 |
| **(viii) Lightering, Transfer, & Storage from Tanks at Risk Procedures** | Not applicable. | |
| **(ix) Transfer and Storage of Recovered Oil/Water; Volume Estimating Procedure** | A temporary storage area and tank farm are established on the CD5 access road. Portable tanks available from on-site equipment inventory temporarily store recovered oil and water until it is recycled into the production stream by in-place production facilities at Alpine. Alpine has at least ten 400-barrel upright and five 500-bbl horizontal oil storage tanks, and up to 22, 59-barrel open-top tanks, seven 14- barrel Fold-a-Tanks, and five 119-barrel bladder tanks are for temporary storage. Additional storage capacity is available from ACS.<br>Portable tanks containing fluids recovered by Task Forces 4, and 5 provide sufficient storage for oil recovered from tundra and water bodies to the east, west, and southwest of the pad. Rolligons with tanks transfer recovered oil and water from these portable tanks to temporary storage at CD5 access road, then vacuum trucks transport fluids directly to the Alpine production facility at CD1 for recycling.<br>The amount of oil is gauged using a Coliwasa tube or by other appropriate means. | D-1<br>L-6<br>R-23 |
| **(x) Plans, Procedures, and Locations for Temporary Storage and Disposal** | A waste management plan is prepared and approved by Unified Command. The appropriate permits for waste storage and disposal are obtained.<br>Temporary storage areas are established within secondary containment on the CD1 airstrip apron, Kuukpik pad, and/or drill sites for interim oil storage, contaminated soils, contaminated gravel, and oily wastes, as needed. Wastes are characterized and disposed of accordingly.<br>Storage tanks and stockpiles are monitored until all contents have been processed.<br>Recovered oil is recycled into the production stream via the processing facility.<br>In winter, the contaminated gravel and soil is transported by truck to Kuparuk DS-1H for processing.<br>Non-liquid oily wastes and non-oily wastes are classified and disposed of accordingly. | D-1 to D-4 |
| **(xi) Wildlife Protection Plan** | Resources at risk primarily are birds. Exclusionary methods are implemented to keep oil away from bird habitat. Additionally, hazing operations are initiated and captive/treatment and stabilization is conducted as needed, under authorization from the appropriate resource agencies. Under Unified Command, the FOSC determines the need for, and makes the request for, resource agency review and authorization. Refer to the *Unified Plan, Annex G: Wildlife Protection Guidelines*.<br>International Bird Rescue is mobilized to make the wildlife stabilization facility operational on Day 2. | W-1 through W-6<br>L-9 |

## TABLE 1-6 (CONTINUED): WELL BLOWOUT IN SUMMER - RESPONSE STRATEGY

| ADEC REQUIREMENT | RESPONSE STRATEGY | ACS TECHNICAL MANUAL TACTIC |
|---|---|---|
| (xi) Wildlife Protection Plan (continued) | Foxes and grizzly bears that may be either in the area or otherwise attracted to the site are hazed from the oiled areas.<br><br>Trained personnel collect dead, oiled wildlife to reduce the risk of other wildlife preying on oiled carcasses. | W2-A<br><br>W-4 |
| (xii) Shoreline Cleanup Plan | Shoreline cleanup operations are initiated based on a plan approved by Unified Command. A shoreline assessment is conducted to understand the nature and extent of oiling and to establish cleanup priorities. Cleanup techniques utilized are based on shoreline type and degree of oiling.<br><br>Primary shoreline cleanup techniques considered include:<br>• Natural recovery for areas of residual oiling where other cleanup techniques would cause harm or damage.<br>• Flooding of minor to moderately oiled shoreline.<br>• Manual or mechanical removal or tilling and aeration of oiled sediments or debris.<br>• Burning of oily vegetation. | SH-1 through SH-6<br><br>B-1 |

## TABLE 1-7: WELL BLOWOUT IN SUMMER - OIL RECOVERY CAPACITY

| A | B | C | D | E | F | G |
|---|---|---|---|---|---|---|
| SPILL RECOVERY TACTIC | NUMBER OF SYSTEMS | RECOVERY OR TRANSFER SYSTEM | OIL RECOVERY RATE PER SYSTEM (bph) or ($yd^3$/hr) | MOBILIZATION, DEPLOYMENT AND TRANSIT TIME TO SITE | OPERATING TIME (hours per 24-hour shift) | RECOVERY CAPACITY B x D x F |
| **TF-3.** On/near pad recovery: R-6, R-7 | 5 | Vacuum truck | 83 bph [1] | 4 hours | 20 | 8,300 bpd |
| **TF-3 Handling Capacity: 8,300 bpd [1]** | | | | | | |
| **TF-4.** On tundra recovery: R-6, R-7 | 3 | Rolligons with tanks transferring to tanks or vacuum truck on CD5 road | 52 bph [2] | Day 2 | 20 | 3,120 bpd |
| | 1 | Vacuum unit, all-terrain with 110-gallon tank | 700 $yd^3$/hr vacuum; 0.5 $yd^3$/hr /tank | Day 2 [3] | 20 | > 50 bpd<br>> 10 $yd^3$/d |
| | 10 | 400-barrel Upright Oil Storage Tanks | (temporary storage) | Day 2 [3] | -- | 4,000 bbl |
| **TF-5.** On tundra/lake recovery R-8, R-24 | 8 | Action AP24MD Drum/Brush skimmer | 20 bph | Day 2 [3] | 20 | 3,200 bpd |
| | 5 | Rope Mop MW-41 skimmer | 5 bph | Day 2 [3] | 20 | 500 bpd |
| | 1 | Lamor MM30 5-Belt Brush skimmer | 50 bph | Day 2 [3] | 20 | 100 bpd |
| | 8 | Manta Ray Slickbar Rigid skimmer | 11 bph | Day 2 [3] | 20 | 1,760 bpd |
| | 37 | 59-barrel Open Top Tank | (temporary storage) | Day 2 [3] | -- | 2,183 bbl |
| | 26 | 3,000-gallon Folding Tank | (temporary storage) | Day 2 [3] | -- | 1,857 bbl |
| | 12 | 600-gallon Folding Tank | (temporary storage) | Day 2 [3] | -- | 171 bbl |
| | 4 | 1000-gallon Folding Tank | (temporary storage) | Day 2 [3] | -- | 95 bbl |
| **TF-4 and TF-5 Handling Capacity: 3,320 bpd [2]** | | | | | | |
| **TF-7.** Oiled gravel removal R-26 | 2 | Dozer/Front-end Loader/Bobcat with Dump Truck | 28 $yd^3$/hr [4] | Day 15, Non-emergency response | 20 | 1,120 $yd^3$/d |
| | 2 | Supersucker | 14 $yd^3$/hr | | 20 | 168 $yd^3$/d [5] |
| **TF-7 Handling Capacity: 1,288 $yd^3$/d** | | | | | | |

1. TF-3 vacuum truck recovery rate is calculated as Oil Recovery Rate (ORR) = Vacuum Truck Capacity / Time, where Time = (miles to disposal * 2 trips / 35 mph) + 2(Tc / Sr), and where:
   miles to disposal is 9.75 from CD5 to CD1
   Tc = Vacuum Truck Capacity = 300 bbl
   Sr = Suction Rate = 200 bph
   Time = (9.75 mi * 2 / 35 mph) + 2(300 bbl / 200 bph) = 3.6 hours
   ORR = 300 bbl / 3.6 hrs = 83 bph

   TF-3 vacuum trucks transfer recovered liquids directly to recycle facilities for disposal; therefore the handling capacity is 8,300 bpd.

2. TF-4 Rolligon tank truck recovery rate: is calculated as ORR = Vacuum Truck Capacity / Time, where:
Time = (miles to transfer point * 2 trips / 5 mph) + 2(Tc / Sr), and where:
Tc = Rolligon tank truck capacity = 238 bbl
Sr = Suction Rate = 114 bph
Time = (1 mile to CD5 road * 2 trips / 5 mph) + 2(238 bbl / 114 bph) = 4.6
ORR = 238 bbl / 4.6 hrs = 51.7 bph

TF-4 Rolligons also support TF-5 to transfer recovered liquids to nearby temporary storage tanks at the CD5 access road. If the Rolligons have a recovery capacity of 3,120 bpd, they can fill the ten (10) 400-bbl storage tanks in one day. Vacuum trucks offload the tanks and transfer recovered liquids directly to recycle facilities for disposal. Two (2) vacuum trucks can offload the temporary storage tanks at a rate of 3,320 bpd (e.g., 2 trucks * 83 bph * 20 h). Therefore, the handling capacity for TF-4 and TF-5 is 3,320 bpd.

3. Equipment utilized is available from existing inventory at Alpine; therefore, it is mobilized and deployed as soon as response strategies and objectives are established. Additional equipment could be mobilized from ACS base and mutual aid operators, if necessary. Derated recovery rate values obtained from ACS *Technical Manual* Tactic L-6.

4. TF-7 dump truck recovery rate is calculated as Tc/(Lt+Tt+Ut), where:
Tc = Truck Capacity = 25 cu yd
Lt = Load Time = 0.25 hr
Tt = Travel Time = miles to lined storage * 2 trips / 35 mph = 9.75 mi * 2 trips / 35 mph = 0.56
Ut = Unload Time = 0.08 hr
Dump Recovery = 25 cu yd /(0.25 hour + (9.75 miles * 2 trips / 35 mph) + 0.08 hour) = 28.2 cu yd/hr

5. Recovery rate is based on Tactic R-5. The Supersucker recovery rate is approximately 14 cu yd per hour. Transit time to lined storage and back is approximately 0.5 hour; therefore, 6 full loads are made per shift.

## TABLE 1-8: WELL BLOWOUT IN SUMMER - RECOVERY AND PROTECTION EQUIPMENT

| RESPONSE FUNCTION | TASK FORCE | TACTIC | EQUIPMENT | TOTAL QUANTITY |
|---|---|---|---|---|
| **SHORELINE AND SENSITIVE AREA PROTECTION UNIT** | | | | |
| Sensitive Area Protection | Priority Protection Sites | C-14 | Work boat<br>Boom | 2<br>variable |
| | Cultural Resource Protection | W-6 | Helicopter | 1 |
| Shoreline Protection | Discharge Tracking | T-4 | Fixed wing aircraft with FLIR | 1 |
| **SPILL RESPONSE UNIT** | | | | |
| Containment and Control Group | **TF-1.** Pad and tundra | C-4 | Backhoe<br>Front-end loader<br>Bobcat with trencher | 1<br>2<br>1 |
| | **TF-2.** Lake | C-5 | Work boat<br>Boom<br>Anchor system | 2<br>>50 ft<br>variable |
| Liquid Recovery Group | **TF-3.** On/near pad | R-6 / R-7 | Vacuum Truck<br>4-inch pumps<br>Suction and discharge hose | 5<br>5<br>variable |
| | **TF-4.** Tundra recovery | R-6 / R-7<br>R-23 | Rolligon<br>4-inch pumps<br>Suction and discharge hose<br>Vacuum Truck | 3<br>3<br>Variable<br>2 |
| | **TF-5.** Tundra and lake | R-8<br>R-24 | Skimmers<br>Storage<br>All-terrain vehicle<br>3- to 4-inch pumps<br>Suction and discharge hose | Up to 22<br>Up to 79<br>2<br>≥ 44<br>variable |
| Oiled Surface Cleanup Group | **TF-6.** Tundra flush and burn | R-4<br>R-9<br><br><br>B-2 | Water Truck or Upright Tank<br>Pump<br>Suction and discharge hose<br>Sorbent boom<br>Weed burner, propane tank | 1<br>1<br>variable<br>variable<br>1 |
| | **TF-7.** Oiled gravel removal | R-21<br>R-26 | Water wash van<br>Front-end loader<br>Bobcat<br>Dump truck<br>Supersucker | 1<br>1<br>1<br>2<br>2 |
| **WILDLIFE PROTECTION UNIT** | | | | |
| Wildlife Hazing Group | Mammal and Bird Hazing | W-2A<br>W-2B | Wildlife hazing kit<br>Propane exploder cannon | 1<br>1 |
| Oiled Wildlife Recovery Group | Capture | W-3 | Helicopter | 1 |
| | Salvage | W-4 | Various transportation | variable |
| | Stabilization | W-5 | ACS Mobile Wildlife Stabilization Center | 1 |

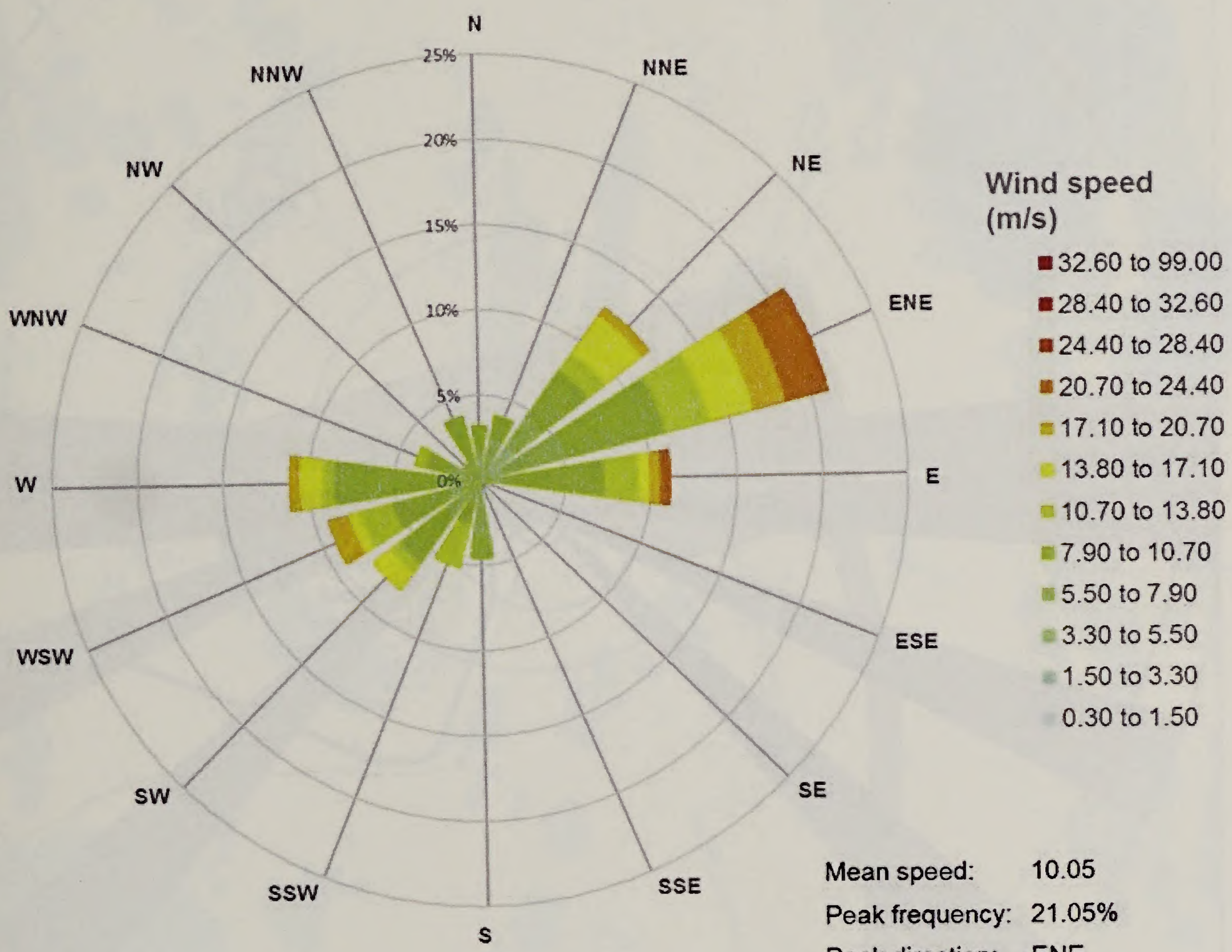
## TABLE 1-9: WELL BLOWOUT IN SUMMER - STAFF TO OPERATE OIL CONTAINMENT, RECOVERY, AND TRANSFER EQUIPMENT

<table>
<tr><th rowspan="2">TASK FORCE</th><th rowspan="2">TACTIC</th><th rowspan="2">NO. UNIT</th><th colspan="5">NO. STAFF PER SHIFT</th><th rowspan="2">NOTE</th></tr>
<tr><th>TEAM LEADER</th><th>SKILLED TECH.</th><th>GENERAL LABORER</th><th>VESSEL OPERATOR</th><th>EQUIPMENT OPERATOR</th></tr>
<tr><td>Protection</td><td>C-14</td><td>1</td><td></td><td></td><td>4</td><td>2</td><td>-</td><td></td></tr>
<tr><td>TF-1</td><td>C-4</td><td>1</td><td rowspan="2">1</td><td>-</td><td>-</td><td>-</td><td>4</td><td rowspan="2">Team Leader supports both TF-1 and TF-2</td></tr>
<tr><td>TF-2</td><td>C-5</td><td>2</td><td>-</td><td>4</td><td>2</td><td>-</td></tr>
<tr><td>TF-3</td><td>R-6, R-7</td><td>5</td><td rowspan="2">1</td><td>5</td><td>-</td><td>-</td><td>5</td><td rowspan="2">Team Leader supports both TF-3 and TF-4</td></tr>
<tr><td>TF-4</td><td>R-6, R-7, R-23</td><td>3</td><td>3</td><td>-</td><td>-</td><td>5</td></tr>
<tr><td>TF-5</td><td>R-8, R-24</td><td>22</td><td>1</td><td>22</td><td>44</td><td>-</td><td>-</td><td></td></tr>
<tr><td>TF-6</td><td>R-4, R-9, B-2</td><td>1</td><td>1</td><td>2</td><td>2</td><td>-</td><td>1</td><td rowspan="2">Deployed after Day 15</td></tr>
<tr><td>TF-7</td><td>R-21, R-26</td><td>1</td><td>1</td><td>-</td><td>2</td><td>-</td><td>7</td></tr>
<tr><td colspan="3">TOTAL</td><td>5</td><td>32</td><td>56</td><td>4</td><td>22</td><td></td></tr>
</table>

## FIGURE 1-3: WELL BLOWOUT IN - SUMMER WIND ROSE DIAGRAM

# Predominant Wind Direction in August (2012-2016)

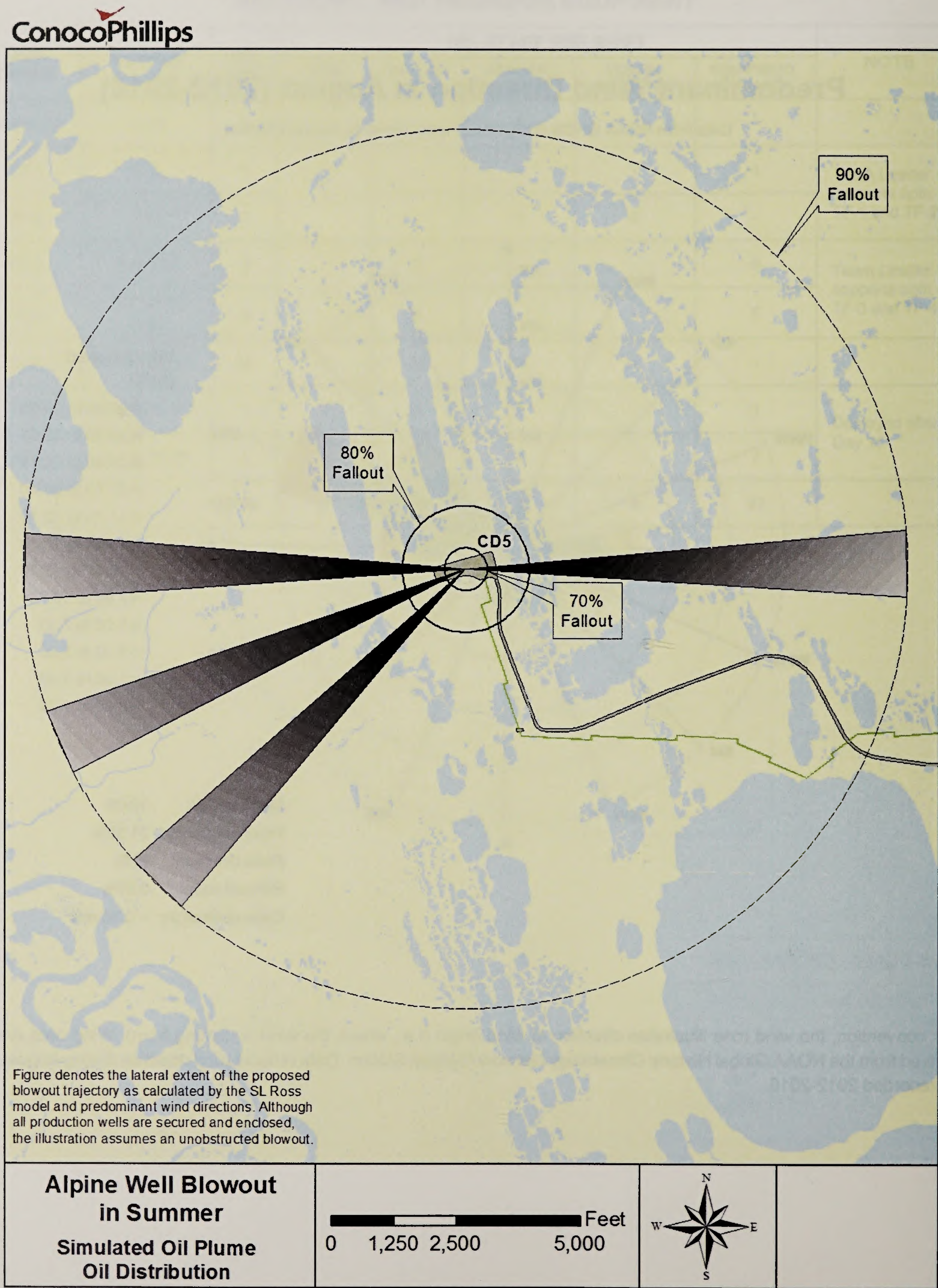
Data from NOAA GHCN Daily Wind Measurements, Nuiqsut Station



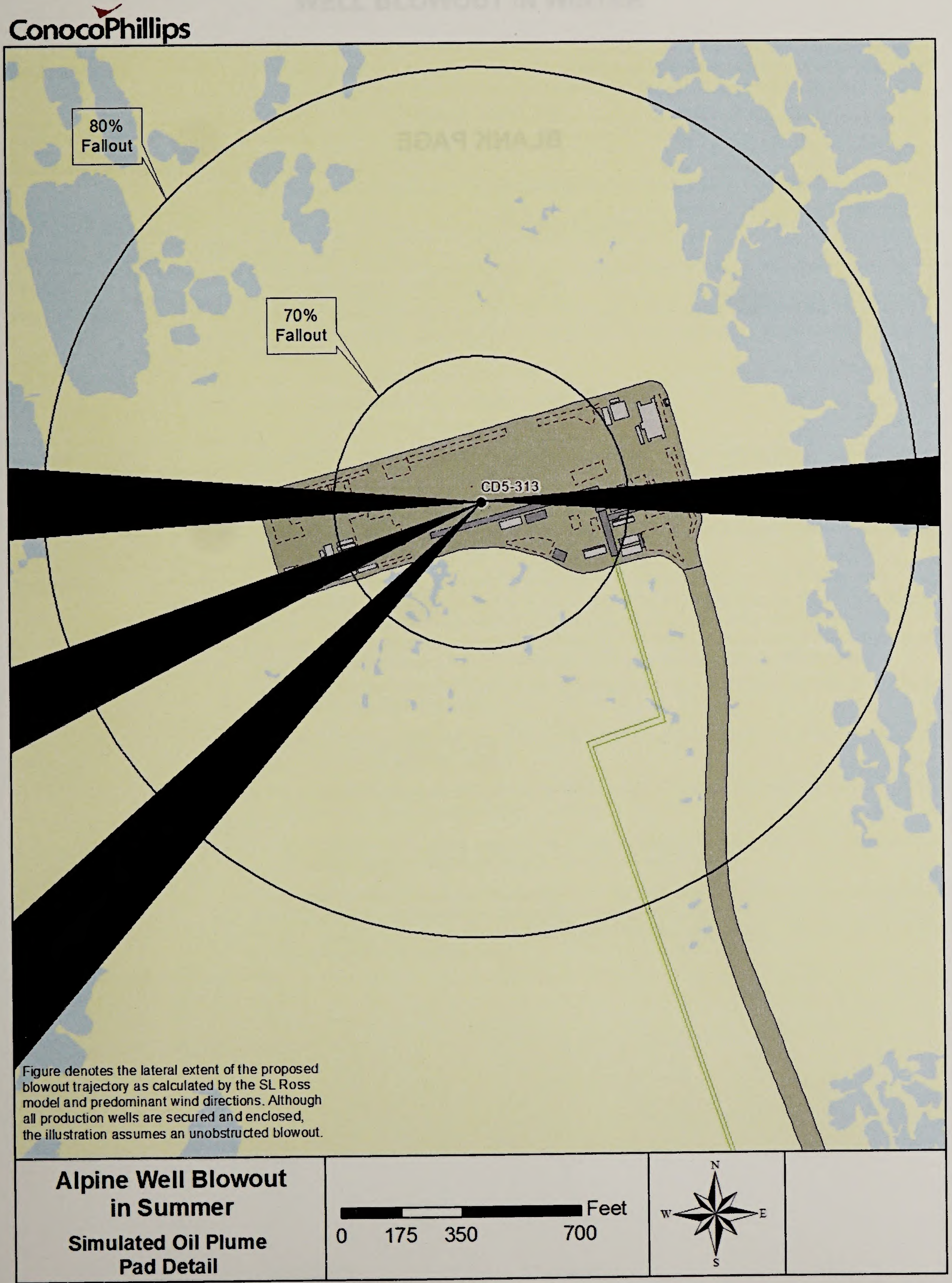

Mean speed: 10.05
Peak frequency: 21.05%
Peak direction: ENE
Percent calm: 0.00%
Calm defined as: < 0.30 m/s

Per convention, the wind rose illustrates direction of wind origin (i.e., where the wind is coming from). Wind data are derived from the NOAA Global Historic Climatology Network Nuiqsut Station. Data reflects wind direction during August, as recorded 2012-2016.

## FIGURE 1-4: SIMULATED OIL PLUME TRAJECTORY FOR SUMMER BLOWOUT



## FIGURE 1-5: SIMULATED OIL PLUME TRAJECTORY FOR SUMMER BLOWOUT - PAD DETAIL



**BLANK PAGE**

## SCENARIO 2

## WELL BLOWOUT IN WINTER

BLANK PAGE

## TABLE 1-10: WELL BLOWOUT IN WINTER - TYPICAL ENVIRONMENTAL CONDITIONS

| | |
|---|---|
| **Spill Location** | Production well CD5-313 on Alpine CD5 Pad |
| **Date / Time** | February 15 / 0800 |
| **Duration** | 15 days |
| **Source of Spill** | Although production wells are secured with a wellhead or blowout preventer while drilling, and are enclosed, this scenario assumes an uncontrolled well blowout occurs through an unobstructed open orifice. |
| **Cause of Spill** | Underbalanced well and failure of pressure control systems. |
| **Quantity of Oil Spilled** | RPS Volume: 150,000 barrels<br>Based on a maximum production rate of 10,000 bopd and a blowout duration of 15 days. |
| **Emulsification Factor** | Not applicable. Oil falls to snow and ice; no oil reaches open water. |
| **Type of Spilled Oil** | North Slope Alpine Crude |
| **Wind Speed** | Average wind speed in February is 27 mph |
| **Wind Direction** | The predominant wind directions are NE, ENE, and E. The winds blow from the NE 50% of the time (8 days), from the ENE 30% of the time (4 days) and from the E 20% of the time (3 days).<br>• Day 1 through 8: wind from NE<br>• Day 9 through 12: wind from ENE<br>• Day 13 through 15: wind from E |
| **Current** | Not applicable. Oil falls to frozen water surfaces; no oil reaches flowing water. |
| **Air Temperature** | -20 °F |
| **Surface** | Well is on a gravel pad located approximately 4 miles west of the Nigliq Channel, and approximately 8 miles west of CD1. Surrounding surface is frozen, snow-covered tundra, and frozen tundra lakes and streams. |
| **Trajectory** | The simulated blowout is discharging at a rate of10,000 bopd with a GOR of 650scf/bbl.<br>The SL Ross plume dispersion model published in ACS *Technical Manual* Tactic T-6 projects that the oil takes the form of an aerial plume extending from the well in the direction of the predominant wind directions. The blowout discharges 150,000 barrels to the SW, WSW, and W of well CD5-313 (Figure 1-6). The model predicts the following plume dimensions:<br>• 70% of the discharged oil falls within 430 feet downwind of the well. At that distance, the plume is about 90 feet wide.<br>• 80% of the discharged oil falls within 1,275 feet downwind of the well. At that distance, the plume is about 235 feet wide.<br>• 90% of the discharged oil falls within 8,885 feet (1.7 mile) downwind of the well. At that distance, the plume is about 1,355 feet wide.<br>• According to the SL Ross model, 10% of discharged oil is in the form of droplets so small (50 micrometers or less) that they do not fall to the ground.<br>Under the SL Ross model, approximately 70% (105,000 barrels) of the discharged oil falls on the CD5 pad. Not all oil falling on the pad is retained by the gravel. If not recovered, discharged oil accumulates in low-lying areas and eventually flows off the pad. Approximately 30,000 barrels of oil falls beyond the pad. |

## TABLE 1-11: WELL BLOWOUT IN WINTER - RESPONSE STRATEGY

| ADEC REQUIREMENT | RESPONSE STRATEGY | ACS TECHNICAL MANUAL TACTIC |
|---|---|---|
| **(i) Stopping Discharge at Source** | Efforts are made to bring the well under control. Emergency shutdown procedures are initiated.<br>When it is determined that control of the well cannot be immediately regained, and safety of personnel is at risk, personnel are evacuated to the pre-designated safe area. At all times, the safety of personnel is COPA's first concern. No unauthorized personnel are allowed near the spill area.<br>The Drilling/Wells Supervisor notifies the Drilling/Wells Superintendent. Security is notified, and the proper notifications and reports are made according to the COPA Drilling & Wells *Emergency Preparedness & Blowout Contingency Plan.*<br>Boots & Coots is activated and dispatched from Houston, Texas within 12 hours.<br>The COPA IMT is activated; the Source Control team develops a well control strategy and coordinates logistics for mobilizing well capping resources.<br>Boots & Coots initiates plans to cap the well.<br>The blowout is controlled on Day 15. | |
| **(ii) Preventing or Controlling Fire Hazards** | Throughout the first few hours of the spill, the Site Safety Officer verifies that all sources of ignition are shut down or removed from the area. The Site Safety Officer provides access zone information and determines PPE requirements. Access to the spill site is carefully controlled and the scene is secured by Security. Monitoring protocol is established by the Site Safety Officer for all work areas to ensure personnel protection. The monitoring protocol establishes safety zones according to applicable Occupational Safety and Health Administration (OSHA) and fire hazard standards. No personnel are allowed in the hot zones unless proper PPE is worn, and it is permitted by the Site Safety Officer.<br>Containment and recovery operations are allowed without respiratory protection in areas where safety criteria are met. Recovery operations, oil field operations, and traffic are not allowed downwind of the blowout well in areas where personnel may become exposed to flash fire hazard or to oil particulate matter at concentrations in excess of permissible exposure limits. Firewater coverage is set up. | S-1 to S-6 |
| **(iv) Surveillance and Tracking of Oil on Open Water; Forecasting Shoreline Contact Points** | Blowout plume model is run. The extent of oil on the snow is delineated so that it can be found if subsequent snowfall or blowing snow covers the spill. Initial estimates are made as to volume of spilled oil. | T-6<br>T-1, T-7 |
| **(v) Protection of Environmentally Sensitive Areas.** | All oil falls to the ground and is absorbed by either the pad or snow. No ACS priority protection sites are impacted. In consultation with ADNR OHA Unified Command identifies cultural sites in the vicinity of the response area so as to avoid disturbance. | ACS Map Atlas, Sheets 6 and 7 |
| **(vi) Spill Containment and Control Actions** | **Task Force 1 (TF-1): Pad Containment and Control**<br>When it is determined safe to do so, berms are constructed on and off the pad to provide initial containment. Containment berms and trenches are built to divert oil to low-lying areas and/or contain it on the pad. Berms and trenches are raised/shored-up on a continuous basis, as needed. Work conducted near the blowout is carefully monitored for safety; no ignition sources are allowed in hot zones and proper PPE is required. | C-1<br>S-1 to S-6 |

## TABLE 1-11 (CONTINUED): WELL BLOWOUT IN WINTER - RESPONSE STRATEGY

| ADEC REQUIREMENT | RESPONSE STRATEGY | ACS TECHNICAL MANUAL TACTIC |
|---|---|---|
| **(vi) Spill Containment and Control Actions (continued)** | **Task Force 2 (TF-2): Frozen Tundra Containment and Control**<br>TF-2 constructs containment berms on frozen tundra using large diameter hoses or sorbent. Areas of lightly oiled snow are contained using water spray and snow fencing.<br>Temporary containment areas are built: Two 150 feet x 200 feet x 2 feet lined storage pits are constructed at Kuukpik Pad. The pits are bermed to a height of 3 feet. The pits contain snow piled to a height of 15 feet. These storage areas are for staging contaminated snow and storing any that cannot be transported off site. | C-4, C-18, C-19<br><br>D-2 |
| **(vii) Spill Recovery Procedures** | On Day 1, the equipment for the recovery, transfer, and interim storage of oiled snow and recovered oil is mobilized. Recovery crews work cross-wind or upwind of the aerial plume. All recovery activities are conducted in accordance with ACS and COPA site entry protocols.<br>**Task Force 3 (TF-3): Liquid Recovery**<br>TF-3 uses seven vacuum trucks to recover oil from low-lying area and bermed and trenched areas containing oil. Vacuum trucks can recover liquid oil up to 200 feet from the truck.<br>Three Rolligons with 10,000 gallon tanks and trash pumps are used for recovery of oil in areas that area inaccessible by vacuum truck. Pumps and hoses in series are also used to recover liquids that are difficult to access. Rolligons transfer fluids to 400-barrel upright storage tanks staged on the CD5 access road to provide temporary on-site storage. Vacuum trucks transfer recovered liquids from the CD5 access road site.<br>**Task Force 4 (TF-4): Mechanical Snow Recovery**<br>TF-4 uses dozers, front-end loaders, trimmers, and Bobcats, to collect oiled snow and load into dump trucks (48 cu yd) to recover oiled snow. Dump trucks transfer oiled snow to interim storage 2.5 miles from the blowout site.<br>**Task Force 5 (TF-5): Manual Snow Recovery**<br>In areas safe for personnel to operate, and after well control is achieved, TF-5 uses of shovels, brooms, snow blowers, snow machines and all-terrain vehicles to collect lightly oiled snow. Dump trucks transfer oiled snow to interim storage 2.5 miles from the blowout site.<br>Once surface control is achieved, allowing full access to the oiled snow. TF-3. TF-4, and TF-5 increase to maximum number of systems. TF-1 and TF-2 demobilize, as containment and control is no longer needed.<br>**Task Force 6 (TF-6): Pad Decontamination**<br>Cleanup and recovery operations are conducted on a non-emergency basis. TF-6 pressure washes oil from the structures on the pad. Once the structures are cleaned, oily gravel is recovered and stored for proper disposal.<br>**Task Force 7 (TF-7): Embedded Oil / Oiled Gravel Removal**<br>Oiled gravel is excavated on a non-emergency basis. Trimmers and front-end loaders excavate oiled gravel. Dump trucks haul the oiled gravel to stockpiles at Kuparuk. | S-1 to S-6<br><br>R-6, R-7, R-23, R-24<br><br>R-1, R-3<br><br>R-2<br><br>R-21<br><br>R-5, R-26<br><br>D-4 |
| **(viii) Lightering Procedures** | Not applicable. | |
| **(ix) Transfer and Storage of Recovered Oil/Water; Volume Estimating Procedure** | Recovered liquids are transported to Alpine production facilities ~~ACF~~ for recycling into the Alpine oil processing stream. Volume of oil is gauged using a Coliwasa tube or by other appropriate means and loads are manifested accordingly.<br>Oiled snow recovered by TF-4 and TF-5 is loaded into dump trucks for transport via the Alpine re-supply ice road to Kuparuk CPF1 for disposal/recycling, according to an approved waste management plan. | D-1, D-5 |

## TABLE 1-11 (CONTINUED): WELL BLOWOUT IN WINTER - RESPONSE STRATEGY

| ADEC REQUIREMENT | RESPONSE STRATEGY | ACS TECHNICAL MANUAL TACTIC |
|---|---|---|
| **(x) Plans, Procedures, and Locations for Temporary Storage and Disposal** | Heavily oiled snow recovered by TF-4 and is taken to the temporary staging areas at Kuukpik pad to await transfer via the Alpine re-supply ice road to Kuparuk CPF1 for interim storage and proper disposal. | D-1, D-2, D-5 |
| | The temporary storage pits are continuously monitored until all contents have been processed. | D-2 |
| | Oil recovered by vacuum trucks is recycled back into the production stream via the Alpine oil processing system. | D-1 |
| | Non-liquid oily wastes are classified and disposed of accordingly.<br>Non-oily wastes are classified and disposed of accordingly. | D-3 |
| | Oiled gravel is transported to a disposal site in Kuparuk, and disposed of accordingly. | D-4 |
| **(xi) Wildlife Protection Plan** | Polar bear monitors are assigned to protect bears and workers. Facilities are made available to agency biologists and veterinarians standing by for potential reports of oiled bears. No wildlife becomes oiled. | W-1, W-2, W-2A, W-2B |
| **(xii) Shoreline Cleanup Plan** | Not applicable. | Not applicable |

# TABLE 1-12: WELL BLOWOUT IN WINTER – OIL RECOVERY AND HANDLING CAPACITY

| SPILL RECOVERY TACTIC | NUMBER OF SYSTEMS | RECOVERY SYSTEM | OILED SNOW RECOVERY RATE [$yd^3$/hr or bph] | MOBILIZATION AND TRANSIT TIME TO SITE [TIME] | OPERATING TIME (hr/day) | HANDLING CAPACITY [$yd^3$/day or bpd] (B X D X F) |
|---|---|---|---|---|---|---|
| **TF-3.** Liquid Recovery R-6, R-7 | 7 | Vacuum truck | 65 bph [1] | 4 hours | 20 | 9,100 bpd |
| **TF-3.** Liquid Recovery R-6, R-7 / R-23 | 3 | Rolligon with 10,000-gallon tank | 52 bph [2] | Day 2 | 20 | 3,120 bpd |
| **TF-3.** Liquid Recovery R-24 | variable | 3- to 4-inch pump, hoses, portable tanks | 52 to 65 bph [3] | Day 2 [4] | 20 | > 1,040 bpd |
| **TF-4.** Mechanical Recovery R-1, R-3 | 6 dump trucks | Dozer/Front-end loader/ Bobcat, 2 Dump trucks | 53 $yd^3$/hr [5] | Day 2 [4] | 20 | 6,336 $yd^3$/d |
| **TF-5.** Manual Recovery R-2 | 20 | Shovels, brooms, all-terrain vehicle/snow machine, front-end loader, dump truck | 3 $yd^3$/hr | Day 15 | 20 | 600 $yd^3$/d |
| **TF-4 & TF-5** Transfer | 20 dump trucks | Front-end loader, 2 Dump trucks | 10.5 $yd^3$/hr [6] | Day 2 [4] | 20 | 4,200 $yd^3$/d |
| **TF-7.** Embedded Oil / Oiled Gravel Removal and Transfer R-5 | 10 (dump trucks) | Trimmer/Front-end loader, Dump truck | 10.5 $yd^3$/hr [6] | Day 15 non-emergency response | 20 | 2,100 $yd^3$/d |

1. **TF-3** vacuum truck recovery rate is calculated as Oil Recovery Rate (ORR) = Vacuum Truck Capacity / Time, where Time = (miles to disposal * 2 trips / 35 mph) + 2(Tc / Sr), and where:
   miles to disposal is 9.75 from CD5 to CD1
   Tc = Vacuum Truck Capacity = 300 bbl
   Sr = Suction Rate = 150 bph
   Time = (9.75 mi * 2 / 35 mph) + 2(300 bbl / 150 bph) = 4.6 hours
   ORR = 300 bbl / 4.6 hrs = 65.2 bph
2. **TF-4** rolligon tank truck recovery rate: is calculated as ORR = Vacuum Truck Capacity / Time, where:
   Time = (miles to transfer point * 2 trips / 5 mph) + 2(Tc / Sr), and where:
   Tc = Rolligon tank truck capacity = 238 bbl
   Sr = Suction Rate = 114 bph
   Time = (1 mile to CD5 road * 2 trips / 5 mph) + 2(238 bbl / 114 bph) = 4.6
   ORR = 238 bbl / 4.6 hrs = 51.7 bph
3. Off pad liquid recovery using hoses and pumps in series can recover at rates exceeding 52 to 65 bph; however, vacuum trucks or Rolligons with tanks offload temporary portable tanks and transport liquids to disposal, so the effective recovery rate is 52 to 65 bph.
4. Equipment utilized is available from existing inventory at Alpine; therefore, it is mobilized and deployed as soon as response strategies and objectives area established. Additional equipment could be mobilized from ACS base and mutual aid operators, if necessary.

5. **TF-4** dump truck recovery rate is calculated as Tc/(Lt+Tt+Ut), where:
   Tc = Truck Capacity = 25 cu yd
   Lt = Load Time = 0.25 hr
   Tt = Travel Time = miles to interim storage * 2 trips / 35 mph = 2.5 mi * 2 trips / 35 mph = 0.14 hr
   Ut = Unload Time = 0.08 hr
   Dump Recovery = 25 cu yd /(0.25 hour + (2.5 miles * 2 trips / 35 mph) + 0.08 hour) = 53 cu yd/hr

6. For **TF-7**, a trimmer set at a six-inch depth can chip approximately 160 $yd^3$ of ice per hour; however, due to the long travel distance to disposal (e.g., Kuparuk DS1H) the recovery rate is based on dump truck handling capacity, as follows:
   **TF-4, TF-5, and TF-7** maxi-haul or Euclid B-70 recovery rate is calculated as Tc/(Lt+Tt+Ut), where:
   Tc = Truck Capacity = 32.5 cu yd
   Lt = Load Time = 0.34 hr
   Tt = Travel Time = miles to storage and disposal at CPF1 * 2 trips / 35 mph = 45 mi * 2 trips / 35 mph = 2.6 hr
   Ut = Unload Time = 0.16 hr
   Dump Recovery = 32.5 cu yd /(0.34 hour + (45 miles * 2 trips / 35 mph) + 0.16 hour) = 10.5 cu yd/hr

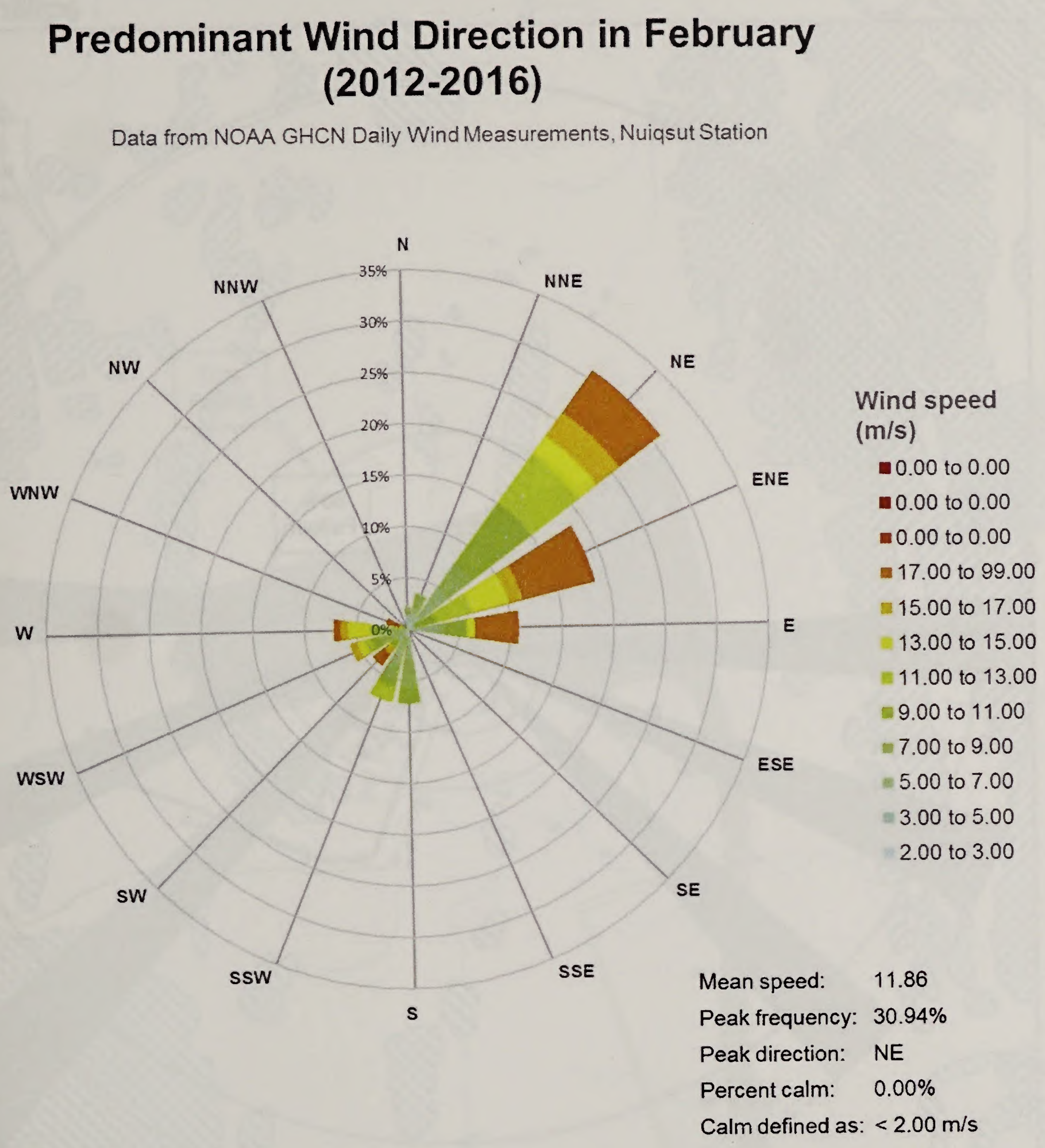
## TABLE 1-13: WELL BLOWOUT IN WINTER - OIL RECOVERY AND TRANSFER EQUIPMENT

| RESPONSE FUNCTION | TASK FORCE | TACTIC | EQUIPMENT | TOTAL QUANTITY |
|---|---|---|---|---|
| **SPILL RESPONSE UNIT** | | | | |
| Containment and Control Group | **TF-1.** Pad | C-1 | Dozer<br>Front-end loader<br>Bobcat | 1<br>3<br>2 |
| | **TF-2.** Tundra | C-4<br>C-18 / C-19 | Backhoe<br>Bobcat<br>Front-end loader<br>Water truck / tank<br>Snow fence<br>Shore seal boom<br>Sandbags | 2<br>2<br>1<br>1<br>variable<br>variable<br>variable |
| Liquid Recovery Group | **TF-3.** Pad and tundra | R-6 / R-7<br>R-23<br>R-24 | Vacuum Truck<br>Rolligon with tank<br>4-inch pumps<br>Suction and discharge hose<br>Storage | 7<br>3<br>10<br>Variable<br>Up to 79 |
| Mechanical Recovery Group | **TF-4.** | R-1 / R-3 | Dozer<br>Front-end loader<br>Bobcat<br>Dump truck | 1<br>3<br>2<br>6 |
| Manual Recovery Group | **TF-5.** | R-2 | Shovel / broom<br>Snow machine/all-terrain vehicle<br>Front-end loader<br>Dump truck (shared with TF-4) | 120<br>20<br>1<br>2 |
| **DISPOSAL UNIT** | | | | |
| Oiled Snow Transfer Group | **TF-4 and TF-5.** | R-3 | Front-end loader<br>Maxi-haul or Euclid B-70 | 10<br>20 |
| **PAD DECONTAMINATION UNIT** | | | | |
| Structure Cleanup Group | **TF-6.** | R-21 | Water wash van/steam unit | 1 |
| Embedded Oil / Oiled Gravel Removal and Transfer Group | **TF-7.** | R-5 | Trimmer<br>Front-end loader<br>Maxi-haul or Euclid B-70 | 5<br>5<br>10 |

## TABLE 1-14: WELL BLOWOUT IN WINTER - STAFF TO OPERATE OIL CONTAINMENT, RECOVERY, AND TRANSFER EQUIPMENT

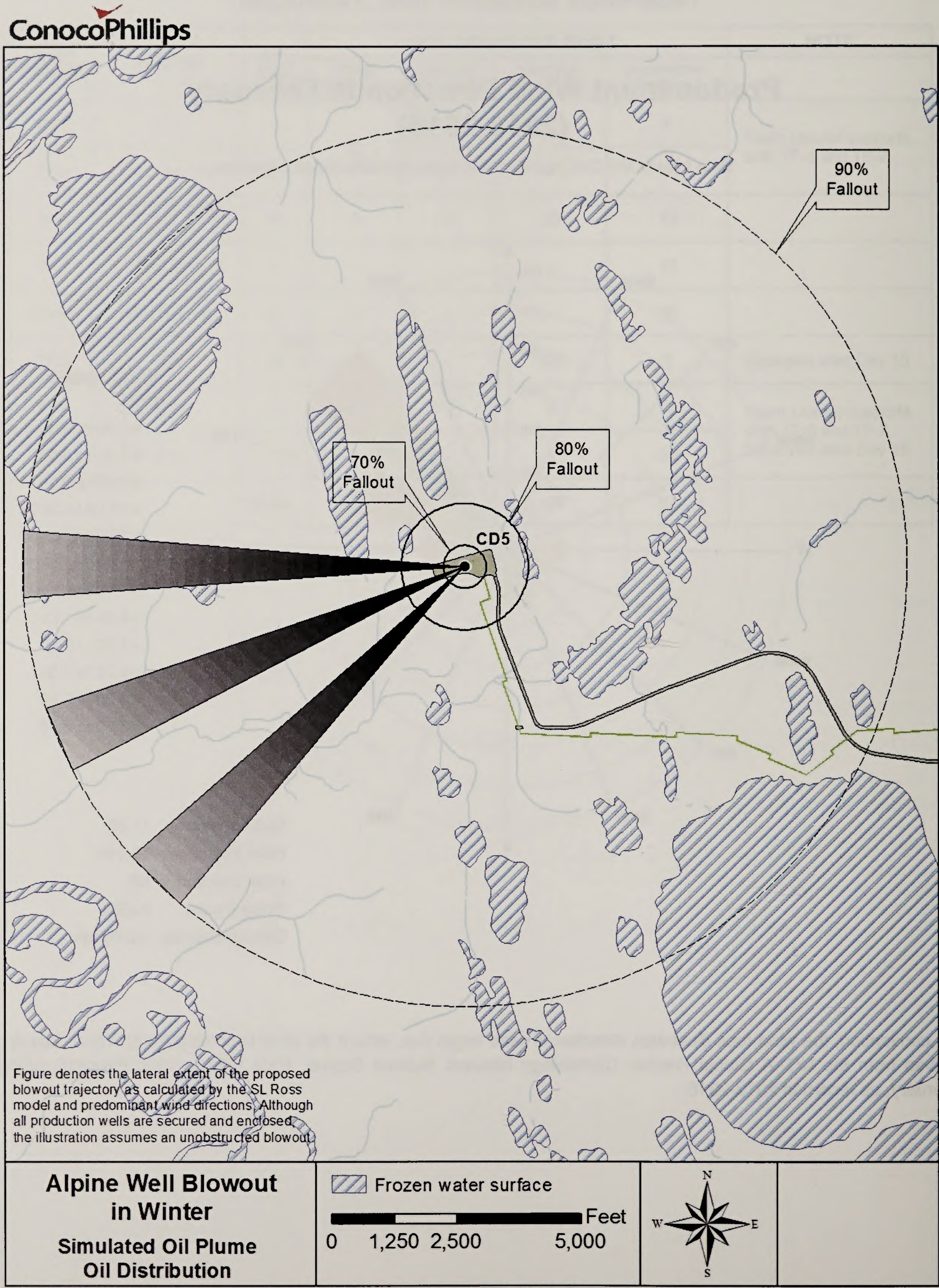
| TASK FORCE | TACTIC | NO. UNIT | NO. STAFF PER SHIFT | | | | NOTE |
|---|---|---|---|---|---|---|---|
| | | | TEAM LEADER | SKILLED TECH. | GENERAL LABORER | EQUIPMENT OPERATOR | |
| TF-1 | C-1 | 1 | 1 | - | - | 6 | Team Leader supports both TF-1 and TF-2 |
| TF-2 | C-4, C-18, C-19 | 2 | | 2 | 4 | 5 | |
| TF-3 | R-6, R-7, R-23, R-24 | 10 | 2 | 10 | 20 | 10 | |
| TF-4 | R-1, R-3 | 3 | 1 | - | - | 12 | |
| TF-4/5 | R-3 Transfer | 10 | - | - | - | 30 | |
| TF-5 | R-2 | 20 | 2 | - | 120 | 3 | Deployed after Day 15 |
| TF-6 | R-21 | 1 | 2 | - | 2 | 1 | Team Leader supports both TF-6 and TF-7. Deployed after Day 15 |
| TF-7 | R-5 | 1 | | - | - | 20 | |
| | | TOTAL | 8 | 12 | 144 | 87 | |

## FIGURE 1-6: WELL BLOWOUT IN WINTER - WIND ROSE DIAGRAM

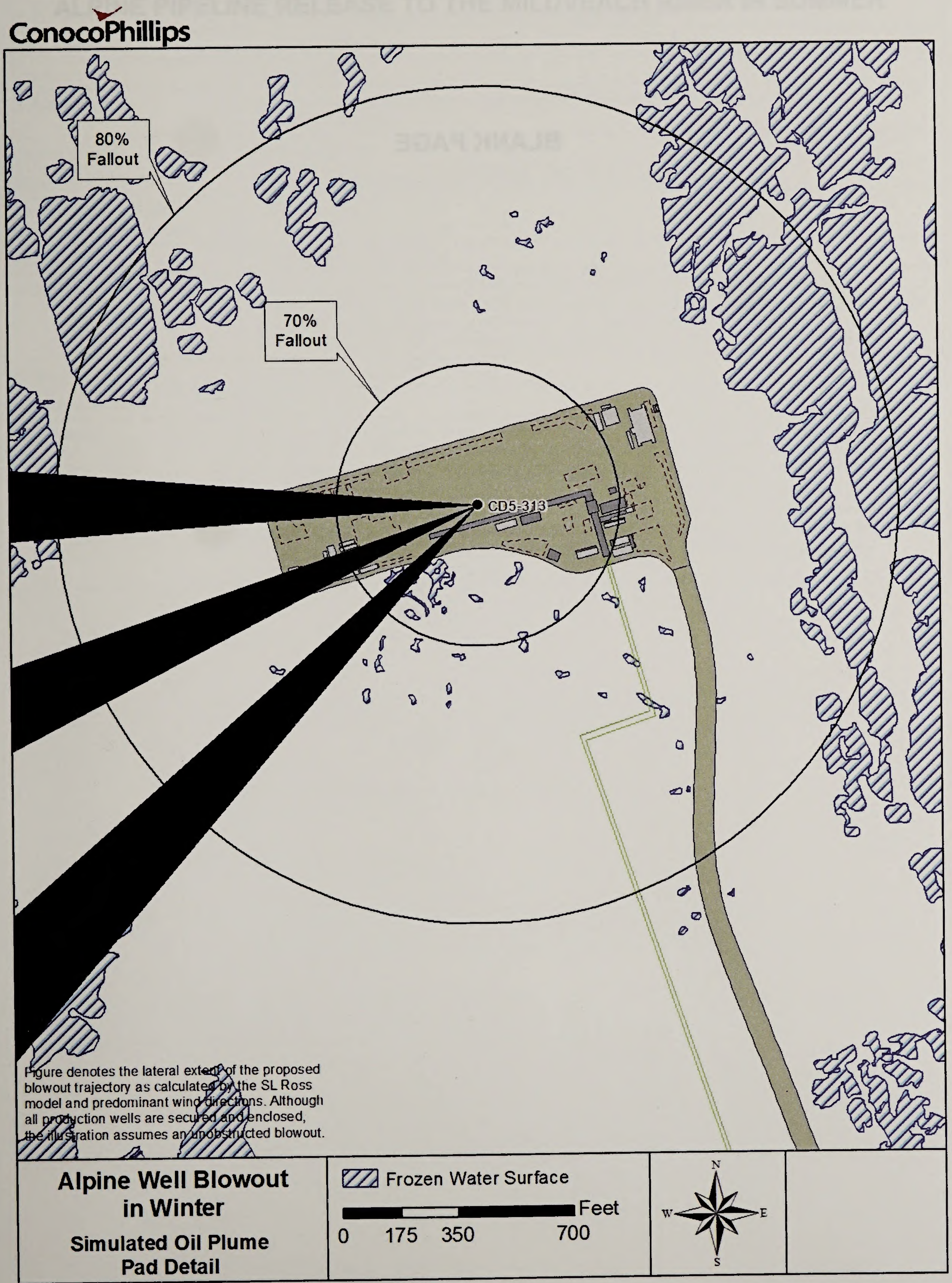



Per convention, the wind rose illustrates direction of wind origin (i.e., where the wind is coming from). Wind data are derived from the NOAA Global Historic Climatology Network Nuiqsut Station. Data reflects wind direction during February, as recorded 2012-2016.

## FIGURE 1-7: SIMULATED OIL PLUME TRAJECTORY FOR WINTER BLOWOUT



## FIGURE 1-8: SIMULATED OIL PLUME TRAJECTORY FOR WINTER BLOWOUT PAD DETAIL



BLANK PAGE

## SCENARIO 3

## ALPINE PIPELINE RELEASE TO THE MILUVEACH RIVER IN SUMMER

BLANK PAGE

## TABLE 1-15: ALPINE PIPELINE RELEASE TO THE MILUVEACH RIVER IN SUMMER - TYPICAL ENVIRONMENTAL CONDITIONS

| | |
|---|---|
| **Spill Location** | Miluveach River crossing (between Vertical Loops 4 and 5) |
| **Date / Time** | July 10 / 0600 |
| **Duration** | Instantaneous |
| **Source of Spill** | 14-inch crude oil transmission pipeline between Alpine processing facility (ACF at CD1) and Kuparuk CPF2 |
| **Cause of Spill** | Pipeline rupture |
| **Quantity of Oil Spilled** | Adjusted RPS volume = 2,830 barrels, all to open water (See Part 5) |
| **Emulsification Factor (for Storage Purposes)** | 1.67 |
| **Oil Type** | Alaska North Slope Crude |
| **Wind Direction and Speed** | Wind data are derived from the NOAA Global Historic Climatology Network Nuiqsut Station. The data used were collected during summer months (May through October) from May 2012 to October 2016 (see Figure 1-24). The average wind speed during summer months is 23 mph. The predominant wind directions are NE, ENE, E, WSW, and W. |
| **Current** | 1.5 knot average (0.71-2.4 knot) |
| **Air Temperature** | 44 °F |
| **Trajectory** | Rupture occurs directly above the water and 2,830 barrels of oil drains from pipeline into the Miluveach River. Oil moves downstream in the current. Wind-influenced trajectory is not considered unless oil leaves the Miluveach/Colville River system into Harrison Bay. The estimated time for oil to reach the first control point (CS-A) is 5 minutes; oil reaches the second control point (CS-B) within 15-25 minutes (see Figure 1-9). Oil entraining past CS-B continues downstream towards the Miluveach confluence with the Colville River. The remaining oil strands on the riverbank before reaching the Colville River, becoming unavailable for open-water recovery. |

## TABLE 1-16: ALPINE PIPELINE RELEASE TO THE MILUVEACH RIVER IN SUMMER - RESPONSE STRATEGY

<table>
<tr><th>ADEC REQUIREMENT</th><th>RESPONSE STRATEGY</th><th>ACS TECHNICAL MANUAL TACTIC</th></tr>
<tr><td>(i) Stopping Discharge at Source</td><td>Upon notification by Security, the Alpine Pipeline Coordinator verifies that the pipelines have been shut in. However, oil and water continue to drain from the higher elevations of the damaged pipe segments for approximately 1 hour.</td><td></td></tr>
<tr><td>(ii) Preventing or Controlling Fire Hazards</td><td>Throughout the first few hours of the spill, the Site Safety Officer verifies that all sources of ignition are shutdown or removed from the area. The Site Safety Officer provides access zone information and determines PPE requirements. Access to the spill site is carefully controlled and the scene is secured by Security. Monitoring protocol is established by the Site Safety Officer for all work areas to ensure personnel protection. Decontamination areas are set up.</td><td>S-1 to S-6</td></tr>
<tr><td>(iv) Surveillance and Tracking of Oil on Open Water; Forecasting Shoreline Contact Points</td><td>Aerial observation using fixed wing aircraft or helicopter is used to provide real time tracking of the leading edge of the oil.<br>Oil trajectory is calculated initially using 100% of the downgradient current. A trajectory using vector addition will be calculated if oil enters Harrison Bay.<br>Tracking buoys are staged at the mouth of the river in the event they are needed to track oil entering Harrison Bay.</td><td>T-4<br>T-5</td></tr>
<tr><td>(v) Protection of Environmentally Sensitive Areas</td><td>Exclusion planning takes into account the protection priorities based on the North Slope Subarea Contingency Plan for Oil and Hazardous Substance Discharges/Releases list of resources of concern and cultural sites described in the ACS Technical Manual, Volume 2, Map Atlas.<br>There are no priority sites on the Miluveach River downriver of the rupture point.<br>The nearest ACS priority protection sites are approximately 4 miles downriver of the at the confluence of the Miluveach and Colville rivers:
<table>
<tr><th>Priority Site #</th><th>Map Atlas</th><th>Boom Length (ft)</th><th>Tactic</th><th>TF</th></tr>
<tr><td>31</td><td>14</td><td>8,000</td><td>C-13</td><td>SPTF#1</td></tr>
<tr><td>43</td><td>14</td><td>500</td><td>C-14</td><td>SPTF#2</td></tr>
</table>
Response activities are conducted away from cultural sites, based on a shoreline cleanup plan approved by the Unified Command in consultation with the ADNR Office of History and Archaeology (OHA).</td><td>C-13 (1)<br>C-14 (1)<br>ACS Map Atlas Sheets 14 and 15<br>Pre-staged Equipment: ACS Map Atlas Sheets 18 and 27</td></tr>
<tr><td>(vi) Spill Containment and Control Actions</td><td>Containment and recovery teams are deployed to pre-designated control sites and are instructed to take steps necessary in order to keep the oil from entering the Colville River.<br>Approximately 350 feet of diversionary boom has been pre-deployed to Control Site A (CS-A), approximately 500 feet downstream of the pipeline crossing. This boom is deployed at the beginning of the summer as a contingency measure for such a scenario. The boom placement is designed to divert the oil into the small oxbow channel at CS-A where it can be recovered or burned. Approximately 60% of the oil is contained at CS-A. See Figure 1-9.<br>Approximately 350 feet of diversionary boom deployed to Control Site B (CS-B), approximately 2,400 feet downstream of the pipeline crossing.. The boom placement is designed to divert the oil into a collection point along the east bank of the river. Approximately 30% of the oil is contained at CS-B. See Figure 1-9.<br>Containment at boom sites is accomplished immediately. ACS location ALP-1 contains the following equipment to support the CS-A and CS-B sites: 1,500 feet of river boom, one 3-inch trash pump, two drum or brush skimmers, two 500-gallon bladders, and eight 2,500-gallon (59-barrel) open top storage units. The total storage capacity pre-staged at ALP-1 is 479 barrels.</td><td>C-8, C-9<br>ACS Map Atlas Sheet 27<br>C-8, C-9<br>ACS Map Atlas Sheet 27</td></tr>
</table>

## TABLE 1-16 (CONTINUED): ALPINE PIPELINE RELEASE TO THE MILUVEACH RIVER IN SUMMER - RESPONSE STRATEGY

| ADEC REQUIREMENT | RESPONSE STRATEGY | ACS TECHNICAL MANUAL TACTIC |
|---|---|---|
| **(vii) Spill Recovery Procedures** | **Task Force 1 (TF-1)** recovers oil at CS-A utilizing a portable skimmer. Floating hoses are used to transfer oil directly from the skimmer to Fastanks on the east bank of the river. Three additional Fastanks and two drum/brush skimmers are mobilized to ensure adequate storage and recovery. The total storage capacity for TF-1 is 418 barrels. Sorbents are utilized in conjunction with skimming operations.<br>**Task Force 2 (TF-2)** recovers oil at CS-B utilizing a portable skimmer. Three additional Fastanks and two drum/brush skimmers are mobilized to ensure adequate storage and recovery. The total storage capacity for TF-2 is 418 barrels. Sorbents are utilized in conjunction with skimming operations.<br>**Task Force 3** is assigned to transfer recovered fluids from CS-A and CS-B to vacuum trucks waiting on the Tarn Road.<br>**Task Force 4 (TF-4)** is deployed to CS-C at the confluence of the Miluveach and Colville rivers. The following equipment is pre-staged at site CS-C (also known as ALP-13): 750 feet of river boom and two anchor systems. Containment boom is deployed to collect any remaining oil before it reaches the Colville River.<br>**Task Force 5** is a contingency open-water recovery system deployed to the waters at the mouth of the Colville River to encounter any oil that may escape up-stream containment and recovery sites. No oil reaches this task force.<br>**Task Force 6** is a shoreline cleanup task force (see xii below).<br>A staging area is set up at the West Sak 15 Pad on the Tarn Road. | R-8, R-9<br>R-8, R-9<br>R-23<br>R-16, R-9<br>R-17<br>SH-1<br>L-2 |
| **(viii) Lightering, Transfer, & Storage from Tanks at Risk Procedures** | Not applicable. | |
| **(ix) Transfer and Storage of Recovered Oil/Water; Volume Estimating Procedure** | Recovered oil at CS-A and CS-B is temporarily stored in Fastanks on site. A Rolligon with a trailer tank transfers the fluids to vacuum trucks waiting on the Tarn Road. The vacuum trucks deliver recovered liquids to Kuparuk CPF-1 for processing.<br>The amount of oil is gauged using a Coliwasa tube or by other appropriate means. | R-23<br>D-1 |
| **(x) Plans, Procedures, and Locations for Temporary Storage and Disposal** | Oily liquids are taken to Kuparuk CPF-1 for handling in the oil processing facility.<br>Non-liquid oily wastes are classified and disposed of according to classification. Sorbent material, Visqueen, and other materials are contained in poly bags and hauled to the NSB incineration facility at Deadhorse.<br>Non-oily wastes are classified and disposed of accordingly. | D-1<br>D-2<br>D-3 |
| **(xi) Wildlife Protection Plan** | Immediate response activities include the preparation of wildlife deterrent systems.<br>A wildlife task force prevents birds and mammals from entering oiled areas onshore and on water. A wildlife stabilization and treatment center is made operational and staffed by Bird Rescue staff by Hour 24. | W-1 to W-6 |

## TABLE 1-16 (CONTINUED): ALPINE PIPELINE RELEASE TO THE MILUVEACH RIVER IN SUMMER - RESPONSE STRATEGY

| | | |
|---|---|---|
| **(xii) Shoreline Cleanup Plan** | Shoreline cleanup operations are initiated once the source of the oil has been stopped and all on-water recovery actions are complete. | |
| | A shoreline assessment is conducted to understand the nature and extent of oiling and to establish cleanup priorities. | SH-1 |
| | Four Shoreline Cleanup Task Forces (TF-6) are deployed along the Miluveach River banks. Shoreline cleanup techniques consist primarily of manual removal, removal by use of sorbents, and cutting of oiled vegetation. | SH-2, SH-5, SH-7 |

## TABLE 1-17: ALPINE PIPELINE RELEASE TO THE MILUVEACH RIVER IN SUMMER - LIQUID RECOVERY CAPABILITY

| A | B | C | D | E | F | G |
|---|---|---|---|---|---|---|
| **SPILL RECOVERY TACTIC** | **NUMBER OF SYSTEMS** | **RECOVERY SYSTEM / SKIMMER NAME AND MODEL** | **DERATED OIL RECOVERY RATE PER SYSTEM (bph)** | **MOBILIZATION, DEPLOYMENT AND TRANSIT TIME TO SITE (hours)** | **OPERATING TIME (hours per 24-hour shift)** | **LIQUID RECOVERY CAPACITY (bbl per day) (B X D X F)** |
| **Day 1** | | | | | | |
| TF-1: R-8 | 1 | Action AP24MD | 20 | On site | 16 | 320 |
| TF-2: R-8 | 1 | Action AP24MD | 20 | On site | 16 | 320 |
| TF-4: R-16 | 1 | Action AP24MD | 20 | 14 | 6 | 320 |
| TF-5: R-17 | 1 | Vikoma weir skimmer | 97 | 14 | 6 | 582 |
| **Days 2-3** | | | | | | |
| TF-1: R-8 | 3 | Action AP24MD | 20 | Mobilized by Day 2 | 20 | 1,200 |
| TF-2: R-8 | 3 | Action AP24MD | 20 | Mobilized by Day 2 | 20 | 1,200 |
| TF-4: R-16 | 1 | Action AP24MD | 20 | On site | 20 | 400 |
| TF-5: R-17 | 1 | Vikoma weir skimmer | 97 | On site | 20 | 1,940 |

## TABLE 1-18: ALPINE PIPELINE RELEASE TO THE MILUVEACH RIVER IN SUMMER - LIQUID HANDLING CAPABILITY

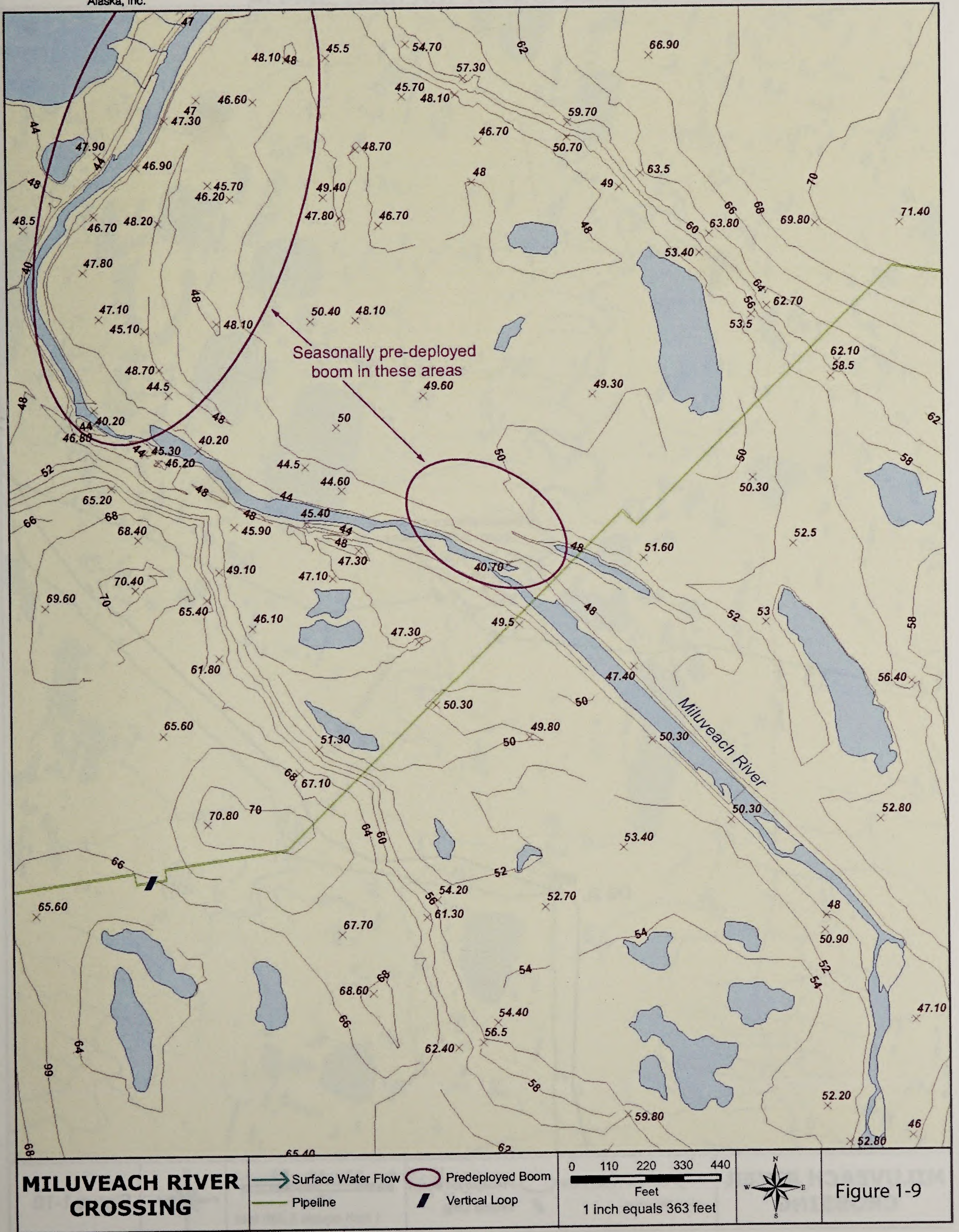
| A | B | H | I | J | K | L | M | N | O | P |
|---|---|---|---|---|---|---|---|---|---|---|
| SPILL RECOVERY TACTIC | NUMBER OF SYSTEMS | STORAGE CAPACITY DESCRIPTION | STORAGE CAPACITY VOLUME (bbl) | OIL / EMULSION AVAILABLE (bph)[1] | TIME ON LOCATION PRIOR TO NEEDING TO OFFLOAD (hrs) I/J | OFF-LOADING MECHANISM | OFF-LOADING RATE (bph) | TRANSIT TIME - BOTH WAYS (hrs) | OFFLOADING TIME (hrs) I/M | OFFLOAD AND TRANSIT TIME (hrs) N+O |
| TF-1: R-8 | 1 | Fastanks (7), Open top (1) | 418 | 33.4 | 12.5 | 3-inch Trash Pump | 485 | NA | 0.5 | NA |
| TF-2: R-8 | 1 | Fastanks (7), Open top (1) | 418 | 33.4 | 12.5 | 3-inch Trash Pump | 485 | NA | 0.5 | NA |
| TF-3: R-23 to R-6 | 1 | Rolligon w/ Trailer Tank | 238 | 66.8 | 4 | Vac Truck | 200 | 4 | 1.2 | 5.2 |
| TF-3: R-6 | 1 | Vac Truck | 300 | 66.8 | 4 | Vac Truck | 200 | 0.6 | 1.5 | 2.1 |

[1] The total volume of oil/emulsion available for recovery is the volume of oil that discharges to water x 1.67 (emulsion factor).

For example, a drum/brush skimmer with a derated recovery rate of 20 bph will require 33.4 bph emulsion storage (20 bph x 1.67 = 33.4 bph).

# FIGURE 1-9: MILUVEACH RIVER CROSSING, DIAGRAM 1

ConocoPhillips
Alaska, Inc.



## FIGURE 1-10: MILUVEACH RIVER CROSSING, DIAGRAM 2

## SCENARIO 4

## ALPINE TANK RUPTURE IN SUMMER

**BLANK PAGE**

## TABLE 1-19: ALPINE TANK RUPTURE IN SUMMER - TYPICAL ENVIRONMENTAL CONDITIONS

| | |
|---|---|
| **Spill Location** | CF-T-61001, a 3,300-barrel Diesel (ultra-low sulfur diesel) Tank |
| **Date** | August 1 |
| **Duration** | Instantaneous release |
| **Cause of Spill** | Unknown |
| **Quantity of Oil Spilled** | RPS Volume: 1,320 barrels<br>Based on a maximum tank capacity of 3,300 barrels with a deduction of 1,980 barrels for secondary containment. |
| **Emulsification Factor** | Not applicable. All diesel is contained on the pad; no diesel reaches open water. |
| **Oil Type** | Diesel (ultra-low sulfur diesel) |
| **Wind Direction and Speed** | Wind data are derived from NOAA Global Historic Climatology Network Nuiqsut Station. The data used were collected during summer months (May through October) from May 2012 to October 2016 (see Figure 1-24). The average wind speed during summer months is 23 mph. The predominant wind directions are NE, ENE, E, WSW and W. |
| **Current** | Not applicable. |
| **Air Temperature** | 44 °F |
| **Surface** | The tank is located on the eastern portion of CD1 pad, approximately 100 feet from the perimeter of the pad and 400 feet from the Sakoonang Channel. The surface between CD1 and the channel is tundra. |
| **Trajectory** | Sixty percent of the diesel is contained in secondary containment. The remaining 40% (1,320 barrels) spreads laterally from the source (tank). Most of the 1,320 barrels migrates downhill (north) to the Tank Farm Basin. |

## TABLE 1-20: ALPINE TANK RUPTURE IN SUMMER - RESPONSE STRATEGY

| ADEC REQUIREMENT | RESPONSE STRATEGY | ACS TECHNICAL MANUAL |
|---|---|---|
| **(i) Stopping Discharge at Source** | Security notifies the SRT. The secondary containment is assessed for repair to prevent further leakage. At all times, the safety of personnel is COPA's first concern. No unauthorized personnel are allowed near the spill area. | |
| **(ii) Preventing or Controlling Fire Hazards** | Throughout the first few hours of the spill, the Site Safety Officer verifies that all sources of ignition are shut down or removed from the area. The Site Safety Officer provides access zone information and determines PPE requirements. Access to the spill site is carefully controlled and the scene is secured by Security. Monitoring protocol is established by the Site Safety Officer for all work areas to ensure personnel protection.<br>No personnel are allowed in the hot zones unless proper PPE is worn, and it is permitted by the Site Safety Officer.<br>Firewater coverage is set up. | S-1 through S-6 |
| **(iv) Surveillance and Tracking of Oil on Open Water; Forecasting Shoreline Contact Points** | The extent of the spill is marked with stakes and hand-held global positioning systems. | T-1 |
| **(v) Protection of Environmentally Sensitive Areas** | No ACS priority protection sites occur within the projected spill footprint or downstream of CD1 along the Nigliq and Sakoonang channels.<br>The nearest priority protection sites are located in Harrison Bay, approximately 7 miles WNW of the pad.<br>Response activities are conducted away from cultural sites, based on a shoreline cleanup plan approved by the Unified Command in consultation with the ADNR Office of History and Archaeology (OHA).<br>A Shoreline Protection Task Force is deployed to Sakoonang Channel to observe conditions. Pre-staged equipment and pre-deployed boom are located at numerous locations along Sakoonang Channel. The resources include:<br>• Seasonal pre-deployed boom in the Sakoonang Channel is maintained; however, no oil is projected to fall in the Sakoonang Channel. Approximately 500 to 750 feet of river boom are deployed at both SK-13 and SK-15 control sites, upstream and downstream of CD1 on the Sakoonang Channel.<br>• Three locations along the Sakoonang Channel contain response equipment. Locations ALP-5, ALP-10, and ALP-14 each contain over 1,000 feet of river boom, a 3-inch trash pump, a drum or brush skimmer, at least two anchor systems and at least four 2,500-gallon (59-barrel) open-top storage units. ALP-5 is located upriver of the release; consequently, all of the equipment is re-allocated to downstream locations.<br>Recovery resources can be redistributed as needed; however, no diesel is expected to reach the water. | Pre-staged Equipment:<br>ACS Map Atlas, Sheets 16, 17, and 20 |
| **(vi) Spill Containment and Control Actions** | Containment and recovery operations begin after safety protocols are established. Work conducted near the release is carefully monitored for safety (see part ii above). The equipment needed to respond to the rupture is located on site (at CD1).<br>**Containment Task Force 1 (CTF-1)** constructs berms and trenches in order to:<br>• Separate pooled diesel from vehicle access routes.<br>• Direct diesel into low-lying areas where recovery is more efficient.<br>• Keep diesel from migrating off pad.<br>**Containment Task Force 2 (CTF-2)**, with four SRT staff and a vessel deploys from its staging location at Alpine. CTF-2 checks the pre-deployed boom in Sakoonang Channel. | S-1 to S-6<br>C-4<br>C-8 |

## TABLE 1-20 (CONTINUED): ALPINE TANK RUPTURE IN SUMMER - RESPONSE STRATEGY

| ADEC REQUIREMENT | RESPONSE STRATEGY | ACS TECHNICAL MANUAL |
|---|---|---|
| **(vii) Spill Recovery Procedures** | **Task Force 1 (TF-1):** Using an on-site vacuum truck, TF-1 begins recovery of diesel from the Tank Farm Basin, trenches, and secondary containment. The recovered diesel is temporarily stored in tanks and bladders. The on-site response equipment inventory includes four 400-barrel upright tanks. The total storage capacity at CD1 exceeds the unadjusted RPS volume for the tank rupture. The recovery rate for TF-1 is detailed in Table 1-21.<br><br>**Task Force 2 (TF-2):** TF-2 consists of a Bobcat or backhoe, loader, dump truck, and Supersucker. TF-2 excavates diesel-contaminated gravel and transports it to temporary lined storage at CD1. The recovery capacity for TF-2 is detailed in Table 1-21.<br><br>The recovery rate capacity of the task forces is greater than the RPS volume of 1,320 barrels. | R-6/R-7<br><br>R-5/R-26 |
| **(viii) Lightering Procedures, Transfer, & Storage from Tanks at Risk** | Not applicable. | |
| **(ix) Transfer and Storage of Recovered Oil/Water; Volume Estimating Procedure** | A Fluid Storage and Transfer Task Force establishes a temporary storage area. Portable tanks and bladders available from on-site equipment inventory temporarily store recovered oil and water until it is recycled into the Alpine production stream using in-place production facilities at Alpine. Over 600 barrels of bladder tanks and 3,286 barrels of tank capacity are available for temporary storage of liquids. | D-1 |
| **(x) Plans, Procedures, and Locations for Temporary Storage and Disposal** | Recovered liquids are transferred from temporary storage and recycled into the Alpine production stream.<br><br>Non-liquid oily wastes are classified and disposed of according to classification.<br><br>Non-oily wastes are classified and disposed of accordingly.<br><br>Temporary containment cells are constructed on site for storage of contaminated gravel. Liner material (20-30 mil pit liner material) is mobilized for construction of lined storage cells. Seams are welded together as constructed. Oiled gravel is later excavated, tested, and hauled to a disposal facility. | D-1<br><br>D-2<br>D-3<br>D-4 |
| **(xi) Wildlife Protection Plan** | The spill is contained on the pad area. No risk to wildlife is anticipated. | Not applicable |
| **(vii) Shoreline Cleanup Plan** | Contaminated materials are recovered as described in vii above. No additional cleanup measures are required. | Not applicable |

## TABLE 1-21: ALPINE TANK RUPTURE IN SUMMER - RECOVERY AND HANDLING CAPABILITY

| A | B | C | D | E | F | G |
|---|---|---|---|---|---|---|
| TASK FORCE / ACS RECOVERY TACTIC | NUMBER OF SYSTEMS | RECOVERY SYSTEM | OIL RECOVERY RATE (BPH OR CU YD/HR) | MOBILIZATION, DEPLOYMENT, AND TRANSIT TIME TO SITE (HOURS) | OPERATING TIME (HOURS IN A 24-HOUR SHIFT) | DAILY DERATED OIL RECOVERY CAPACITY (BPD OR CU YD PER DAY) (B X D X F) |
| **RECOVERY OF LIQUIDS** | | | | | | |
| TF-1[A]: R-6/R-7 | 1 | Vacuum truck recovery by direct suction | 96 | 2 Hours[B] | 20 | 1,920 |
| | | | | | **Total (bbl):** | **1,920** |
| **RECOVERY OF OILED GRAVEL** | | | | | | |
| TF-2[C]: R-26 | 1 | Bobcat or backhoe, front-end loader, and dump truck | 45 | 2 Hours[B] | 20 | 900 |
| TF-2[D]: R-5 | 1 | Supersucker | 14 | 2 Hours[B] | 20 | 280 |
| | | | | | **Total (cu yd):** | **1,180** |

NOTES:

A. TF-1 liquid recovery rates are based on a distance of 2 road miles from the recovery area to the temporary storage site. The time in transit, including load/unload time is 3 hours. The load time is calculated using an average pumping rate of 200 bph (rate for diesel). The assumed travel speed is 35 mph. Alpine has an on-site inventory of three vacuum trucks.

B. All response equipment is located on site. The time required to mobilize the equipment and transport it to the release site also includes the time required to establish safety protocols.

C. TF-2 recovery rate is based on Tactic R-26. The recovery rate for gravel is dependent on the following:

$Tc/(Lt+Tt+Ut)$ = 20 cu yd/(0.25 hour + (2 miles * 2 trips / 35 mph) + 0.08 hour) = 45.0 cu yd/hr, where

Tc = Truck Capacity, Lt = Load Time, Tt = Travel Time, Ut = Unload Time

D. TF-2 recovery rate is based on Tactic R-5. The Supersucker recovery rate is approximately 14 cu yd per hour.

# FIGURE 1-11: ALPINE CD1 PAD DETAIL - TANK RUPTURE IN SUMMER

BLANK PAGE

## 1.7 NON MECHANICAL RESPONSE OPTIONS [18 AAC 75.425(e)(1)(G)]

COPA will request approval for in situ burning from the Federal On-Scene Coordinator (FOSC) and State On-Scene Coordinator (SOSC) when mechanical response methods prove ineffective or when in situ burning will be used as a tool to minimize environmental damage. Due to the close proximity of the local resident population of Nuiqsut, additional considerations are discussed before approval of in situ burning by the Unified Command.

Use of dispersants is not considered in this ODPCP. Information about use of dispersants in Alaska, including procedures for obtaining use authorization are presented in the Alaska Regional Response Team Unified Plan, Annex F, Appendix 1: *Alaska Regional Response Team Dispersant Use Plan for Alaska.*

### 1.7.1 Obtaining Permits and Approvals

Burning will not occur without approval by local, state, and federal agencies. The COPA Incident Commander will discuss the option of in situ burning with the federal and state on-scene coordinators. COPA will complete an “Application and Burn Plan” as provided in the ARRT Unified Plan *In Situ Burning Guidelines for Alaska*.

### 1.7.2 Decision Criteria for Use

In situ burning of spilled oil is considered under conditions such as the following:

- Mechanical recovery is impractical or ineffective.
- Shorelines are threatened.
- Burning would augment the oil elimination capacity of mechanical recovery.
- Present and forecast wind conditions will carry the smoke plume away from populated areas.
- A successful test burn has been conducted.

### 1.7.3 Implementation Procedures

If the COPA Incident Commander decides to use in situ burning and obtains the necessary authorization, ACS carries out the response as described in the ACS *Technical Manual* Tactics B-1 through B-6 and L-6.

### 1.7.4 Required Equipment and Personnel

ACS maintains the equipment and personnel for in situ burning. The equipment and personnel are described in the ACS *Technical Manual,* Volume 1 Tactics B-1 to B-6 and SH-10, incorporated here by reference.

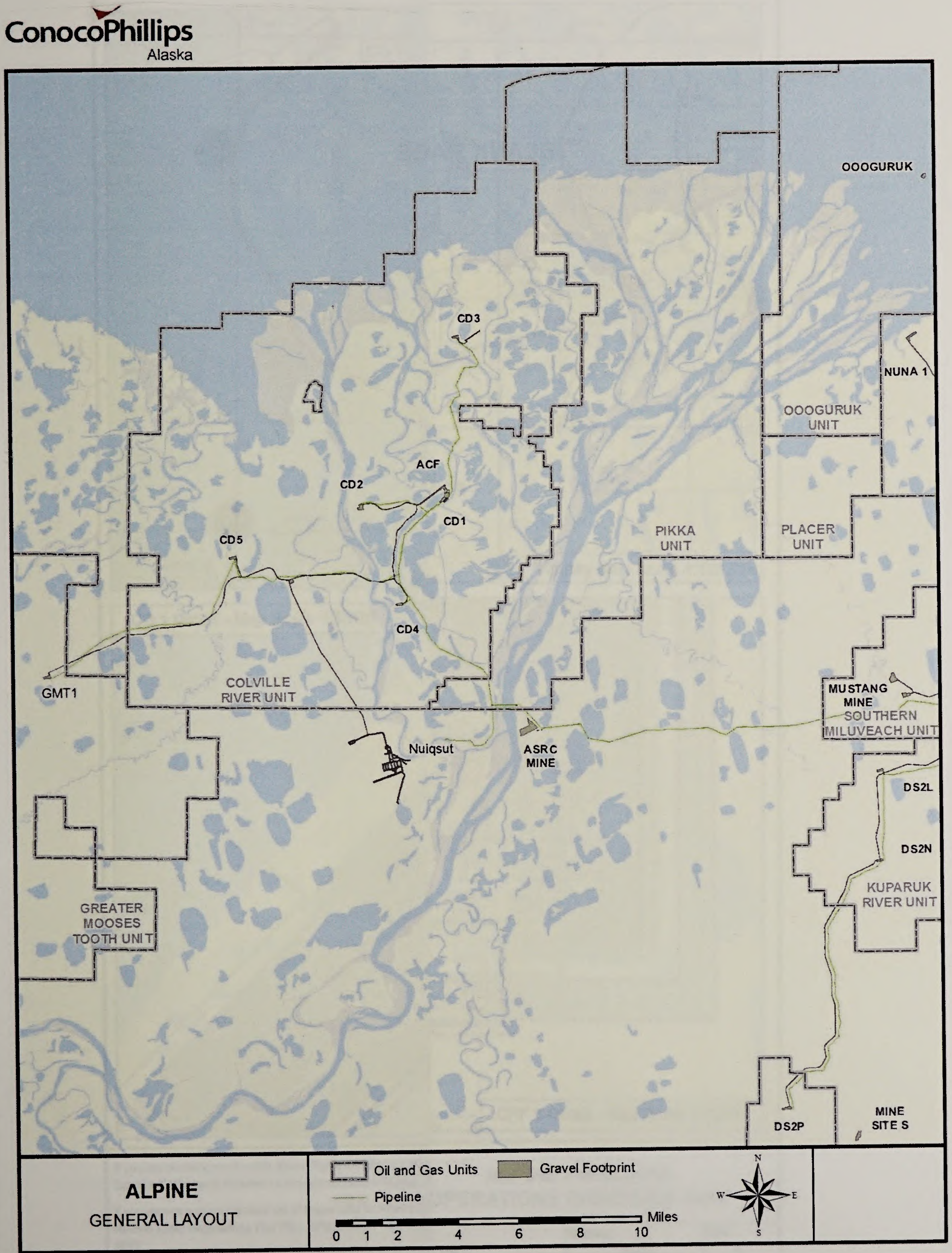
## 1.8 FACILITY DIAGRAMS [18 AAC 75.425(e)(1)(H)]

The ACS *Technical Manual,* Volume 2, Map Atlas contains maps covering the North Slope oil fields showing facilities, roads, pipelines, culvert locations, pre-staged response equipment, ACS priority protection sites, topography, hydrology (including drainage divides and flow directions), and shoreline types.

The following vicinity maps and facility diagrams are provided:

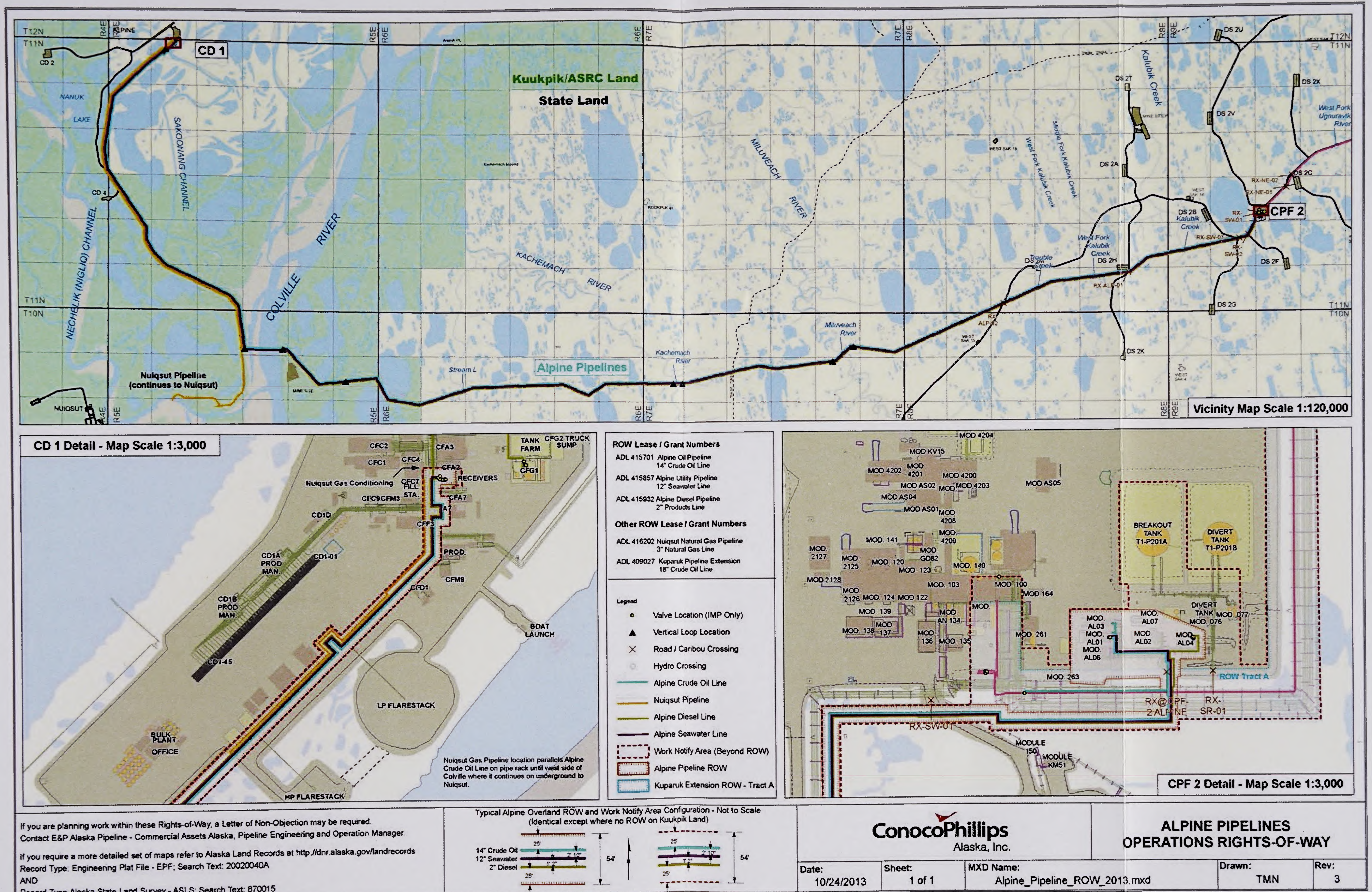
- Alpine Development Area (Figure 1-12)
- Alpine Pipelines Operations Rights-of-Way (Figure 1-13)
- CD1, CD2, and CD3 Vicinity Map (Figure 1-14)
- CD1 Pad Layout (Figure 1-15)
- CD2 Pad Layout (Figure 1-16)
- CD3 Pad Layout (Figure 1-17)
- CD4 Vicinity Map (Figure 1-18)
- CD4 Pad Layout (Figure 1-19)
- CD5 Vicinity Map (Figure 1-20)
- CD5 Pad Layout (Figure 1-21)
- GMT1 Vicinity Map (Figure 1-22)
- GMT1 Pad Layout (Figure 1-23)

# FIGURE 1-12: ALPINE DEVELOPMENT AREA



**BLANK PAGE**

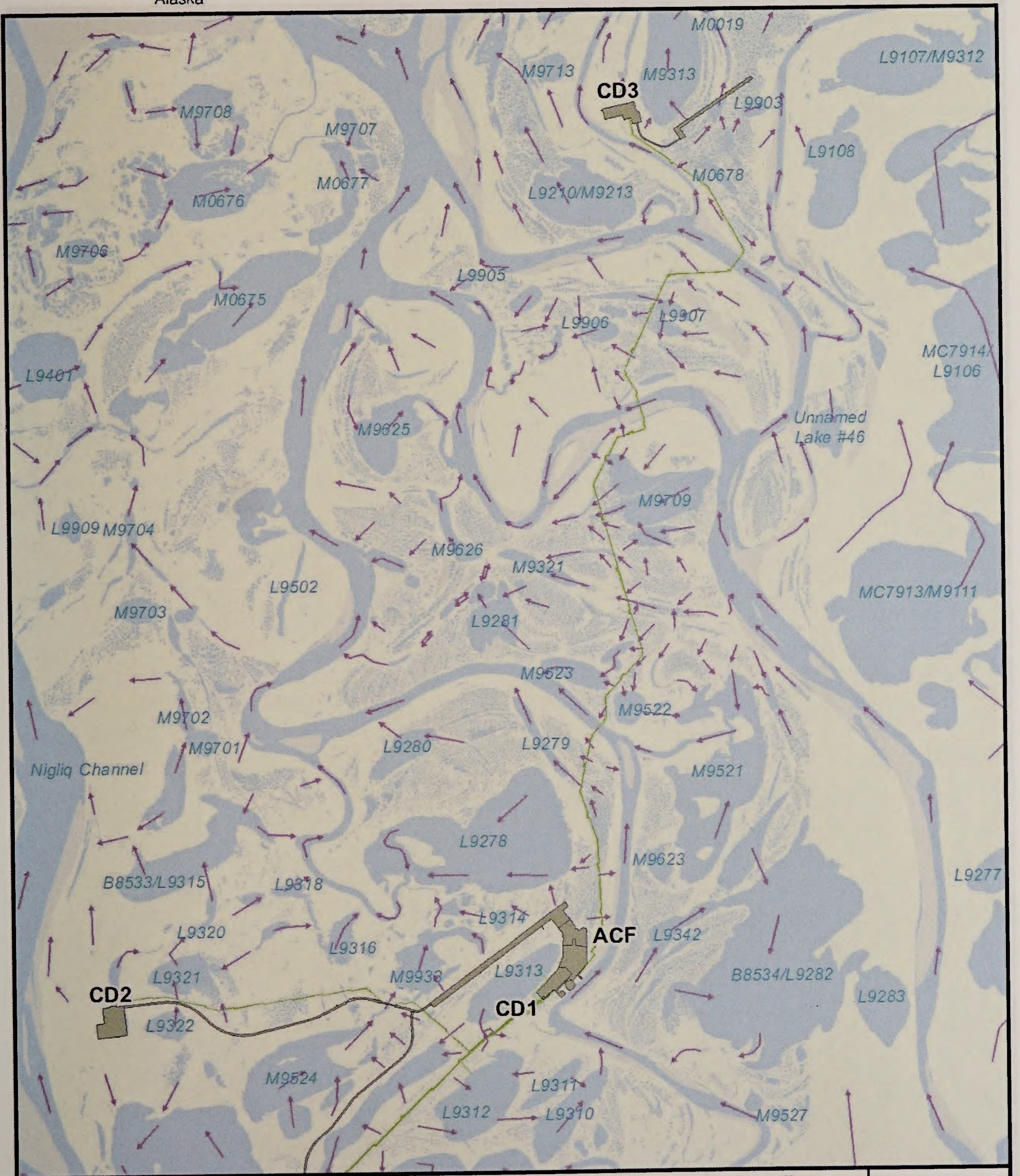
FIGURE 1-13: ALPINE PIPELINES OPERATIONS RIGHTS-OF-WAY



BLANK PAGE

## FIGURE 1-14: CD1, CD2, AND CD3 VICINITY MAP

ConocoPhillips
Alaska



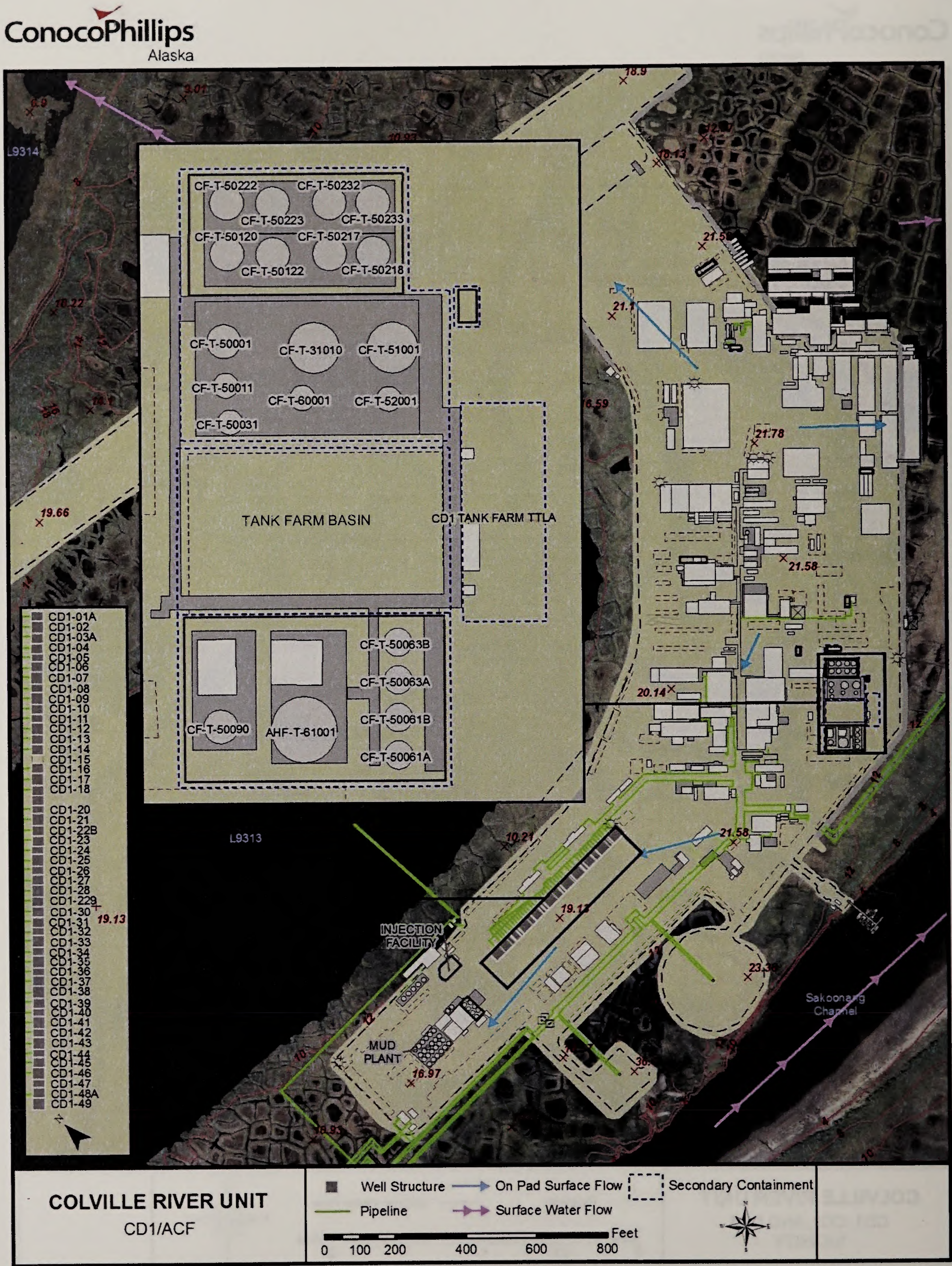

**COLVILLE RIVER UNIT**
CD1, CD2, AND CD3
VICINITY

Pipeline — Surface Water Flow

0 0.5 1 2 Miles

N S W E

## FIGURE 1-15: CD1 PAD LAYOUT



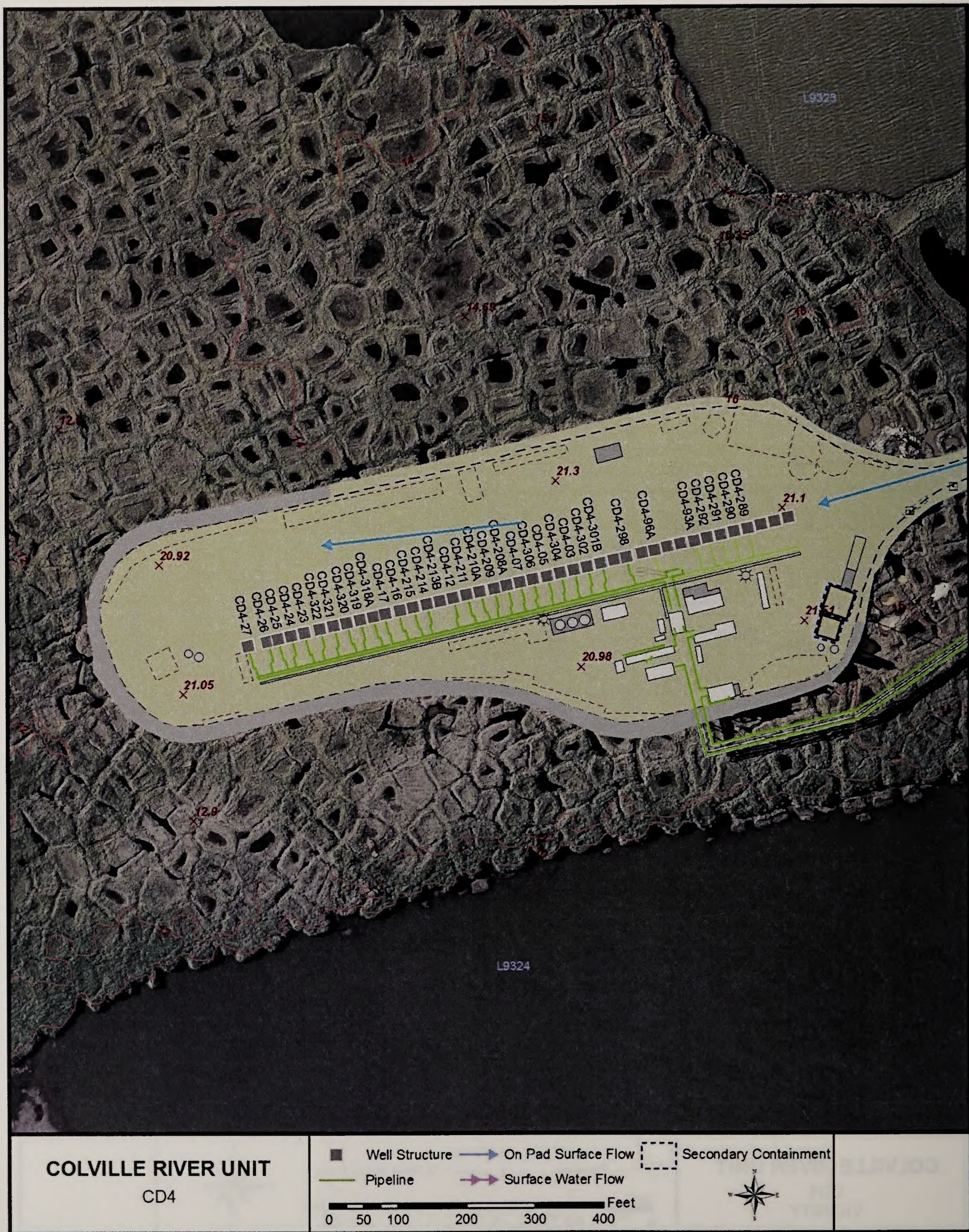
## FIGURE 1-16: CD2 PAD LAYOUT

## FIGURE 1-17: CD3 PAD LAYOUT

## FIGURE 1-18: CD4 VICINITY MAP

# FIGURE 1-19: CD4 PAD LAYOUT

ConocoPhillips Alaska




**COLVILLE RIVER UNIT**

CD4

## FIGURE 1-20: CD5 VICINITY MAP

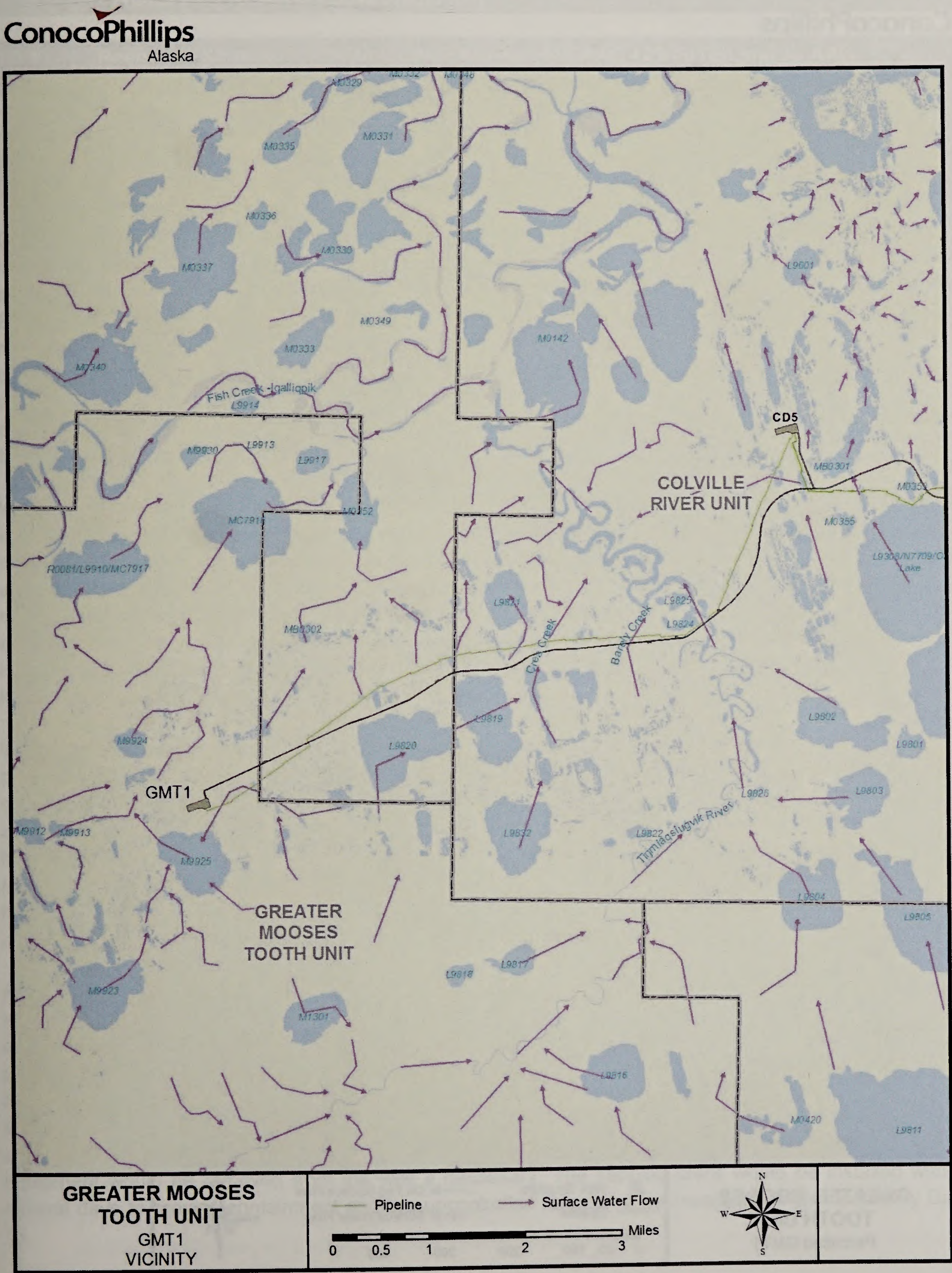
ConocoPhillips
Alaska

# FIGURE 1-21: CD5 PAD LAYOUT

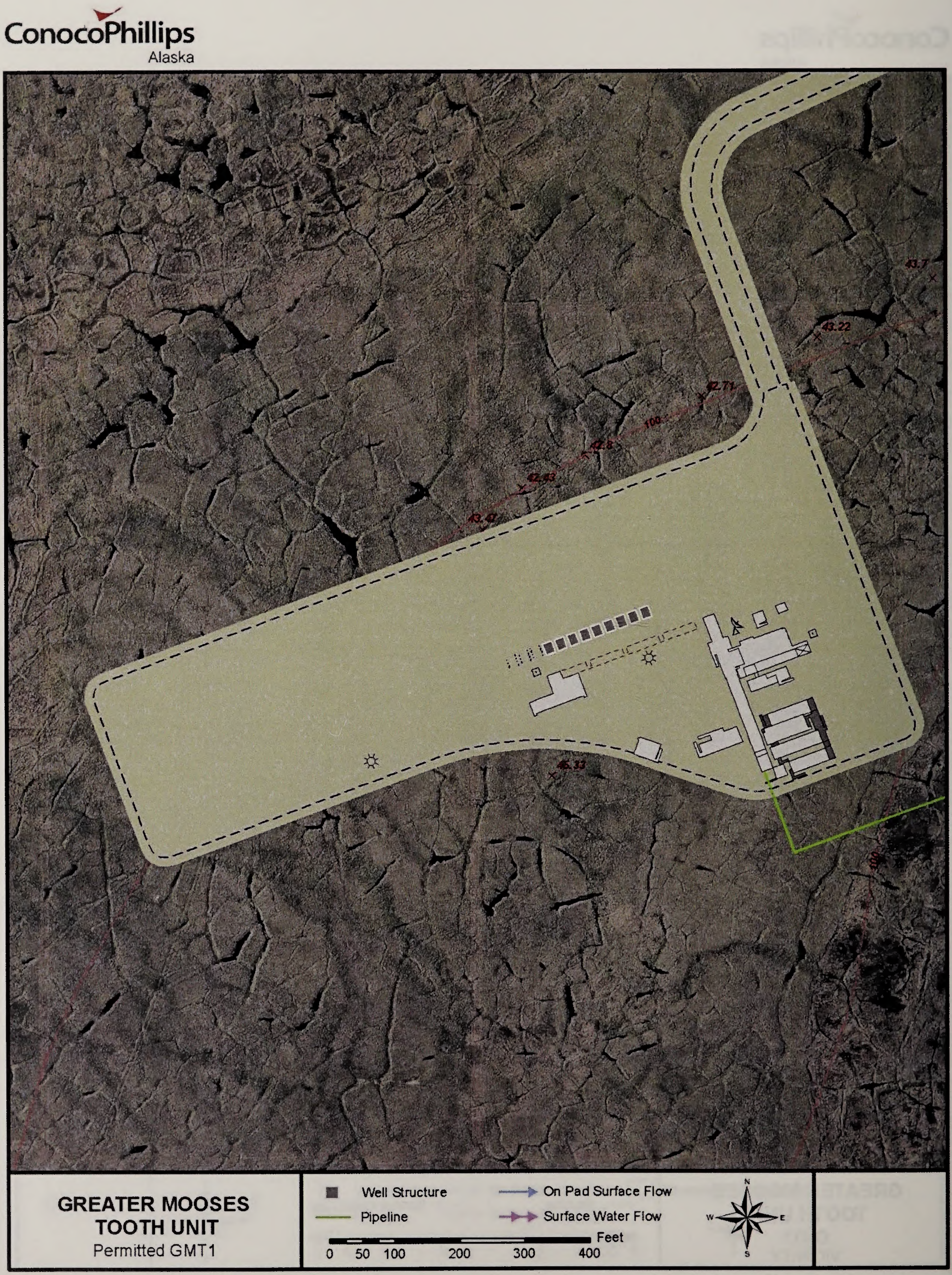
ConocoPhillips
Alaska


| COLVILLE RIVER UNIT<br>CD5 | Well Structure / On Pad Surface Flow / Secondary Containment / Pipeline / Surface Water Flow<br>0 60 120 240 360 480 Feet |
|---|---|

# FIGURE 1-22: GMT1 VICINITY MAP



## FIGURE 1-23: GMT1 PAD LAYOUT



## 1.9 RESPONSE SCENARIO FOR AN EXPLORATION OR PRODUCTION FACILITY [18 AAC 75.425(e)(1)(I)]

### 1.9.1 Response Strategy to Control a Well Blowout [18 AAC 425(e)(1)(I) and 18 AAC 75.445(d)(2)]

Well blowout scenarios include a summary of planned methods, equipment, logistics, and timeframes proposed to be employed to control a well blowout within 15 days. Well blowout scenarios are presented in Section 1.6.3.

COPA has precautions in place that minimize the potential for a loss of well control. If an uncontrolled flow occurs at the surface, safety procedures would be employed to protect personnel, stop the spill, protect the environment, and protect the equipment. The COPA Drilling and Wells *Emergency Preparedness and Blowout Contingency Plan* describes initial response procedures and incident management roles and responsibilities to guide well control specialists in the event of uncontrolled flow at the surface. COPA certifies the *Plan* is a separate well blowout contingency plan that is not part of this ODPCP. It provides step-by-step process to develop detailed incident-specific plans and actions to regain control. An electronic copy of the COPA Drilling and Wells *Emergency Preparedness and Blowout Contingency Plan* is available to COPA drilling operations personnel.

Well control specialists are promptly notified in the event of a well control situation with the potential to escalate. COPA Drilling and Wells Source Control Team provides company and external technical expertise, assistance, and resources to support IMT actions. In addition, COPA maintains an operating agreement with Boots & Coots, a well control specialist contractor that can assist in the intervention and resolution of any well control emergency. Boots & Coots services include, but are not limited to, firefighting equipment and services, specialty blowout control equipment and services, directional drilling services, high-pressure pumping services, and experience with specialty fluids, chemicals, and additives. The 24-hour phone number for Boots & Coots is provided in Figure 1-1.

Well capping operations would commence with COPA activation of Boots & Coots and mobilization of key personnel and equipment. Attempts at dynamic and surface well control methods would continue, if safe conditions exist. If the well capping option is selected, safe reentry to the wellhead area must be established and rig equipment must be moved. If the rig moving system is unavailable or inactive, then heavy bulldozers, block and tackle, and/or cranes would be used to remove the rig from the wellhead area. Once safe access is regained, capping operations can commence. COPA, North Slope operators, and oil field service vendors have available, most major equipment items that would be required to initiate well capping or other surface control options. Specialized equipment required for well capping is summarized in Table 1-22.

An estimated time frame to control a well blowout by means of a well capping program is 15 days, excluding weather days and other contingencies. Mobilization of well control specialist teams and initial equipment, and initiation of well intervention planning is generally expected to take 2 to 3 days. On-site actions to prepare the damaged well and surrounding area would take another 3 to 4 days. Concurrently, site access and safety, well-capping engineering, and well re-entry planning would occur, and decontamination and off-site operations facilities would be mobilized and deployed. Uncontrolled fluids may be diverted for collection and handling to create a safe working environment and minimize pollution. The blowout prevention equipment would be removed from the well if necessary. The capping stack would be installed within several days to provide containment and the uncontrolled release of hydrocarbons is terminated by Day 15.

## TABLE 1-22: WELL CAPPING EQUIPMENT LIST

| COMPONENT | WELL CAPPING USAGE | LOCATION | MOBILIZATION |
|---|---|---|---|
| 6,000-gallon per minute Fire Pumps | Fire and heat suppression | North Slope | <24 hours |
| Athey Wagons | Tractorized booms for manipulation of tools in and around blowout well | North Slope | <24 hours |
| Bulldozers | Power for Athey wagons and backup for heavy equipment moving; can also be used for constructing berms to aid in spill containment | North Slope | <24 hours |
| Backhoes | Drainage ditch, berm construction | North Slope | <24 hours |
| 100-200 ton Cranes | Heavy equipment lifting capability; if well blowout is ignited, may be needed to facilitate rig move | North Slope | <24 hours |
| 50-75 ton Cranes | Smaller, mobile units for spotting support equipment | North Slope | <24 hours |
| 250-500 ton Drilling Blocks | Block and tackle system for moving or dragging heavy equipment | North Slope | <24 hours |
| Drilling Line | Component of block and tackle system if rig moving system is inoperable | North Slope | <24 hours |
| 20-inch and 30-inch Casing | Used to construct Venturi tubes to divert blowing well bore fluids (ignited and un-ignited) | North Slope | <24 hours |
| Miscellaneous Equipment | High pressure chicksan, flexible hoses, valves, containment boom, absorbent, hand tools | North Slope | <24 hours |
| Junk Shot Manifold | Manifold system constructed to pump small leak sealing materials into well | North Slope | <24 hours |
| Hot Tap Tool | Manifold used to gain safe access to pressurized tubulars at surface | North Slope | <24 hours |
| Crimping Tool | Sized device used to pinch tubulars closed to seal off internal flow | Houston, Texas | <48 hours |
| Abrasive Cutter | High-pressure cutting tool used to sever leaking BOPs, rig structures | Duncan, Oklahoma | <48 hours |
| Kill Pumps | Back up to rig pumps | North Slope | <48hours |
| Capping Stack | Various high pressure BOP stacks (to replace leaking, damaged or severed primary BOPs) | Houston, Texas | <10 days |
| Heavy Lift Helicopter | Helicopter capable of lifting | U.S. Pacific Northwest | < 10 days |

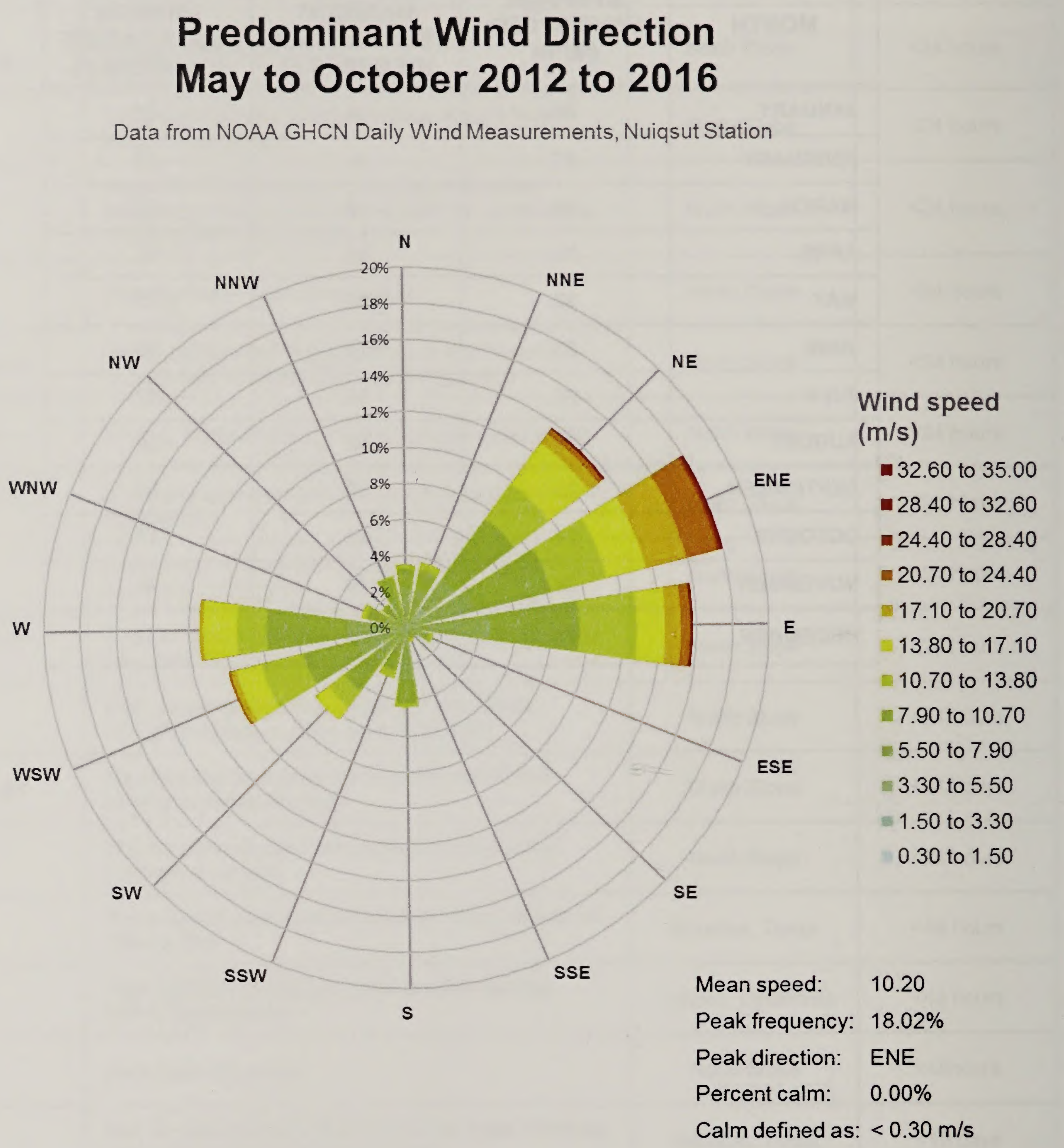
### 1.9.2 Response Scenario Typical Environmental Conditions [18 AAC 75.425(e)(1)(I)(iii)]

The response scenarios in this ODPCP were developed under typical summer environmental conditions during May through October and typical winter environmental conditions during November through April. The average wind speeds, temperatures, and predominant wind directions are derived from publicly available meteorological measurements recorded by National Oceanic and Atmospheric Administration Global Historical Climatology Network Station data from Nuiqsut, Alaska. Table 1-23 shows average wind speed and temperature, and Figures 1-24 and 1-25 are a wind rose diagrams depicting predominant wind directions during summer and winter, respectively. The data were collected for years 2012 to 2016.

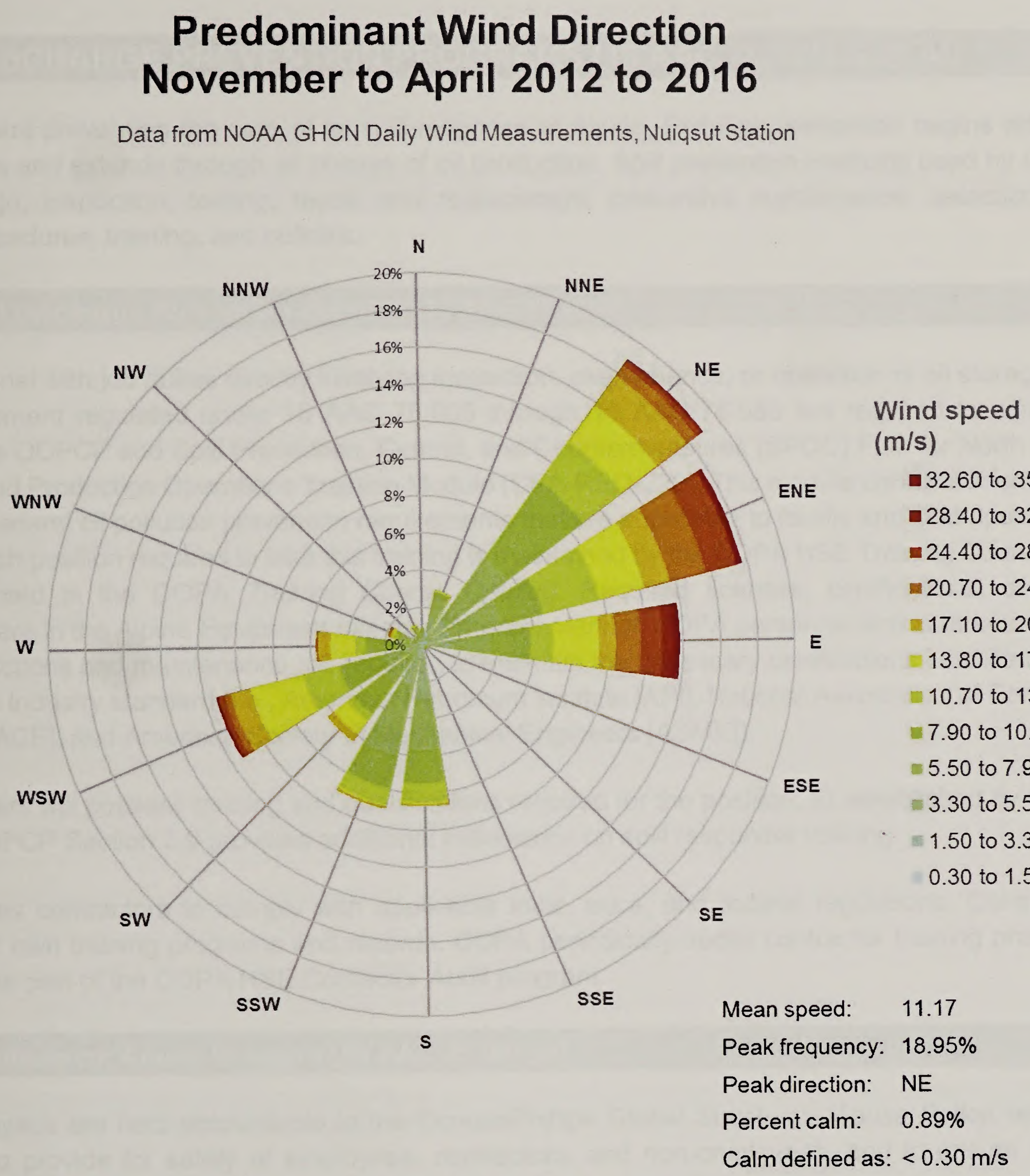
## TABLE 1-23: AVERAGE WIND SPEED AND TEMPERATURE

| MONTH | AVERAGE WIND SPEED (MPH) | AVERAGE MAXIMUM TEMPERATURE (DEGREES F) | AVERAGE MINIMUM TEMPERATURE (DEGREES F) |
|---|---|---|---|
| JANUARY | 28 | -8 | -21 |
| FEBRUARY | 27 | -6 | -20 |
| MARCH | 24 | -9 | -22 |
| APRIL | 25 | 10 | -4 |
| MAY | 22 | 32 | 21 |
| JUNE | 23 | 52 | 36 |
| JULY | 22 | 58 | 42 |
| AUGUST | 22 | 52 | 39 |
| SEPTEMBER | 23 | 39 | 30 |
| OCTOBER | 24 | 28 | 17 |
| NOVEMBER | 24 | 10 | -4 |
| DECEMBER | 23 | -4 | -18 |

## FIGURE 1-24: SUMMER WIND ROSE DIAGRAM



## FIGURE 1-25: WINTER WIND ROSE DIAGRAM



# PART 2 PREVENTION PLAN [18 AAC 75.425(e)(2)]

## 2.1 DISCHARGE PREVENTION PROGRAMS [18 AAC 75.425(e)(2)(A)]

COPA considers prevention the core of its spill response at Alpine. Pollution prevention begins with the drilling of wells and extends through all phases of oil production. Spill prevention methods used by COPA include: design, inspection, testing, repair and replacement, preventive maintenance, detection and shutdown procedures, training, and policies.

### 2.1.1 Oil Discharge Prevention Training [18 AAC 75.020]

COPA personnel with job duties directly involving inspection, maintenance, or operation of oil storage and transfer equipment regulated under 18 AAC 75.005 through 18 AAC 75.080 are required to complete training on the ODPCP and Spill Prevention, Control, and Countermeasures (SPCC) Plan for North Slope Exploration and Production Operations Training Module (CPA-REQ-229). This module contains information on state and federal oil pollution prevention requirements that are applicable to facility and field operations. A listing of each position required to take this training is maintained by the COPA HSE Training Coordinator and documented in the COPA *Training Course Catalog.* Required licenses, certifications, or other prerequisites are in the Alpine *Equipment Integrity Program Manual.* COPA personnel and contractors who perform inspections and maintenance are required to maintain the necessary certifications consistent with the applicable industry standard (i.e., American Petroleum Institute [API], National Association of Corrosion Engineers [NACE], and American Society of Mechanical Engineers [ASME]).

Spill responders will possess training and qualifications required for the position, as established by COPA and ACS. ODPCP Section 3.9 provides additional information on spill responder training.

COPA requires contractors to comply with applicable local, state, and federal regulations. Contractors maintain their own training programs and records. COPA periodically audits contractor training programs and records as part of the COPA HSE Contactor Audit program.

### 2.1.2 Substance Abuse Program [18 AAC 75.007(e)]

COPA employees are held accountable to the ConocoPhillips *Global Substance Abuse Policy,* which is established to provide for safety of employees, contractors, and non-employees, and to ensure a safe working environment at all operations. The Global Policy includes:

- Zero tolerance for violations of the Global Policy.
- Pre-employment drug testing.
- Random drug and alcohol screening and screening for reasonable suspicion/cause.
- Routine training and communication of the Global Policy.
- Opportunities for rehabilitation for voluntary disclosure of substance abuse problems.

Upon entering Company premises, all COPA employees and contractors are expected to comply with COPA's substance abuse program. As provided in the *Alaska Safety Handbook* General Safety Rules, illegal substance and alcohol use or possession is prohibited while on Company property. All personnel

must notify their Supervisor if taking prescription medication that may inhibit their job performance. Prescription drugs should be kept in the original container.

In addition, operation of the Alpine Pipeline is under the jurisdiction of DOT regulations, which require drug testing for pre-employment, random, post-accident, reasonable cause, and return-to-duty situations for employees who operate in designated DOT positions that may include tasks on a pipeline in an operating, maintenance, or emergency response function regulated by 49 CFR Parts 192, 193, or 195 .

### 2.1.3 Medical Monitoring [18 AAC 75.007(e)]

COPA employees engaged in work that requires medical monitoring under federal Occupational Safety and Health Administration (OSHA) and state Alaska Department of Occupational Safety and Health requirements must meet minimum medical and physical requirements for their job classification. Employees and contractors who may be required to use respiratory protection while performing specified job task(s) must follow the COPA *Respiratory Protection Procedure*. Employee enrollment in the COPA Hearing Conservation Program is based on job classification; affected employees must follow the COPA *Hearing Conservation Procedure*.

All members of COPA's HAZMAT Team and Fire Department are given a physical examination that complies with National Fire Protection Association standards. SRT members are given a physical examination every two years. Upon medical clearance, HAZMAT, Fire Department, and SRT members perform respirator fit testing in accordance with the COPA *Respiratory Protection Procedure*.

A medical evaluation may be required if personnel are exposed to, or may be exposed to, hazardous substances at or above the permissible exposure level. If a permissible exposure level does not exist, published exposure levels may be used instead. The exposure will be the ambient air concentration (regardless of respirator use). Medical surveillance also will be provided at the employee's request.

If overexposure is known or suspected as a result of an accidental release, the exposed employee(s) is examined and treated as necessary. Physician's Assistants who work under the direction of a medical doctor can render medical attention. If a Physician's Assistant is not available at Alpine, one can be flown from Kuparuk within one hour, if necessary. Persons requiring additional medical attention are taken to Anchorage by air ambulance or by commercial or Company charter.

### 2.1.4 Security and Surveillance Programs [18 AAC 75.007(f)]

Access to Alpine is available year-round through a privately owned on-site airstrip. Limited ice road access may be available via established checkpoints during winter months. All visitors are required to sign-in upon arrival. Security staff monitor personnel arriving and departing the site by routine patrol and security check points.

### 2.1.5 Fuel Transfer Procedures [18 AAC 75.025]

Employees and contractors must follow established safety procedures for conducting fuel transfers in order to prevent spills or overfilling during a transfer of oil. Under 18 AAC 75.025, "transfer" means any movement of oil within an *oil terminal facility* or between an *oil terminal facility* and a tank truck. As a *production facility*, fuel transfers at Alpine are primarily conducted as:

- Transfer operations from a tank truck to a stationary tank at permanent unloading areas;

- Transfer operations from a stationary or portable tank to a tank truck or other equipment; and
- Transfer between a tank and other drilling or production equipment through hose or piping.

Fuel transfer operations follow *North Slope Environmental Field Handbook* North Slope Fluid Transfer Guidelines, which prescribe:

- Use of established procedures and/or checklist.
- Use two people, if necessary; ensure communication among workers is clear.
- Maintain constant line-of-sight throughout entire operation; be prepared to stop the transfer immediately.
- Inspect hoses, connections, valves, etc. before and after transfer operations.
- Check tank level and overfill protection on regulated tanks prior to start.
- Use surface liners and sorbents.
- Never leave the operation unattended.
- Upon completion, check for spills; report all spills immediately.

The COPA *Fluid Transfer Procedure* gives general procedures for conducting fluid transfer at COPA North Slope facilities. The Procedure provides pre- and post-job actions, as well as a Fluid Transfer Procedure Checklist that may be used, if an established standard form is not already in use.

### 2.1.6 Operating Requirements for Exploration and Production Facilities [18 AAC 75.045]

Under 18 AAC 75.045(a), oil produced during a formation flow test or other drilling operations is collected and stored in a manner that prevents the oil from entering the land or waters of the state. If flow tests are conducted at Alpine, oil produced from these tests will be stored in mobile tanks or flowed directly to the processing facility.

The requirements for platform integrity inspections and isolation valves for pipelines leaving platforms under 18 AAC 75.045(b) and (c) do not apply..

A typical well house includes a cellar box (sump) constructed with steel metal pipe set into the gravel pad to a depth of 5 feet below grade, with a layer of concrete or, for installations after December 30, 2008, a steel bottom seal-welded to the conductor. The design helps contain fluid leaks at the wellhead and facilitates cleanup [18 AAC 75.045(d)].

Catch tank requirements do not apply [18 AAC 75.045(e)].

Onshore oil storage tanks meet requirements of 18 AAC 75.066 and 18 AAC 75.075. See Sections 2.1.10 and 2.1.11.

Onshore piping meets requirements of 18 AAC 75.080. See Section 2.1.7

Drilling operations meet AOGCC requirements for primary and secondary well control to mitigate risks associated with drilling wells on the North Slope.

## 2.1.7 Requirements for Flowlines and Facility Oil Piping [18 AAC 75.047 and 18 AAC 75.080]

### Flowlines

Alpine has a network of flowlines (three-phase oil/water/gas, miscible injection, water, and gas injection) between the processing facility at CD1 and the satellite drill sites. Flowlines are aboveground, with the exception of below-road-grade sections at road crossings. Table 2-1 summarizes flowline compliance measures in place to meet requirements of 18 AAC 75.047.

**TABLE 2-1: FLOWLINE COMPLIANCE MEASURES**

| 18 AAC 75.047 | FLOWLINE REQUIREMENT | INDUSTRY STANDARD | COPA MEASURE |
|---|---|---|---|
| (b) | Design and construction for liquid hydrocarbon, other liquids, and gas. | ASME B31.4-2002<br>ASME B31.8-2003 | Company engineering standards for flowlines are in accordance with industry standards. |
| (c)(1) | Corrosion control and monitoring program for liquid hydrocarbon and other liquids. | ASME B31.4-2002 | Company engineering and asset integrity management procedures. |
| (c)(2) | External corrosion control of buried or submerged metallic piping. | NACE RP0169-2002 | Company engineering and asset integrity management procedures. |
| (c)(3) | External corrosion control of aboveground flowlines with coatings or corrosion-resistant alloy, or another method. | None | Aboveground flowlines are protected from atmospheric corrosion by fusion bonded epoxy (FBE) and/or construction of corrosion resistant alloy. |
| (c)(4) | Program designed to minimize internal corrosion. | None | Company engineering and asset integrity management procedures. |
| (d)(1) | Completely contain the entire flowline and provide interstitial leak detection. | None | Not applicable. Flowlines are managed under a preventative maintenance program instead. |
| (d)(2)(A) | Preventative maintenance program for submerged flowlines. | ASME B31.4-2002 chapters VII-IX | Not applicable. The facility has no submerged flowlines. |
| (d)(2)(B) | Preventative maintenance program for buried flowlines. | ASME B31.4-2002 chapters VII-VIII | Company engineering and asset integrity management procedures. |
| (d)(2)(C) | Preventative maintenance program for aboveground flowlines. | API 570*<br>ASME B31.4-2002 chapters VII-VIII | Company engineering and asset integrity management procedures. |
| (d)(2)(D) | Procedures to review operational changes that may impact pipeline integrity. | None | Management of change procedures address operational changes and potential impact to flowlines. |
| (e) | Line markers installed at road crossings and at one-mile intervals. | None | One-mile interval markers waived per September 13, 2007 ADEC letter; see Section 2.6 for waiver letter. |
| (f) | "Removed from service" ** for more than one year must be free of oil and notify ADEC. For piggable pipeline, a cleaning pig used and for other pipelines use gravity drainage; or evacuate by air or other method. | None | Company engineering and asset integrity management procedures. Out-of-service notices are sent to ADEC on regular intervals. |
| (g) | Aboveground flowlines must be supported consistent with Paragraph 421 of ASME B31.4-2002. | ASME B31.4-2002 paragraphy 421 | Flowline support design is consistent with the standard. |
| (h)(1) and (2) | Verify compliance with requirement to have programs for corrosion control and preventative maintenance through documentation of inspections, tests, evaluation, analysis, repairs, procedures, and audtis. | None | Company engineering and asset integrity management procedures. Records, tests, and information are maintained in an electronic database and files. |

* API 570, Second Edition, October 1998, Addendum 1, February 2000, Addendum 2, December 2001, and Addendum 3, August 2003, excluding Section 8; adopted by reference (effective 12/30/2006, Register 180)

** For purposes of this section, "removed from service" means not in regular use for the service intended and not included in a regular maintenance and inspection program.

## Facility Piping

Facility oil piping at Alpine includes piping and associated fittings connected to an aboveground storage tank regulated under 18 AAC 75.066 and piping from a production well (sometimes referred to as "well line") up to the connection to a flowline. Table 2-2 summarizes facility oil piping compliance measures in place to meet requirements of 18 AAC 75.080.

**TABLE 2-2: FACILITY OIL PIPING COMPLIANCE MEASURES**

| 18 AAC 75.080 | FACILITY OIL PIPING REQUIREMENT | INDUSTRY STANDARD | COPA MEASURE |
|---|---|---|---|
| (b) | Corrosion control program for metallic piping containing oil. | None | Company engineering and asset integrity management procedures. |
| (c) | Design and construction for process piping, liquid hydrocarbon, other liquids, and gas. | ASME B31.3-2004<br>ASME B31.4-2002<br>ASME B31.8-2003 | Company engineering standards for piping are in accordance with industry standards. |
| (d) | Protect buried metallic piping in service between May 14, 1992 and December 30, 2008 with protective coating * and cathodic protection. | None | The facility has no buried facility oil piping meeting this criteria. |
| (e) | Buried piping in service after December 30, 2008 is of welded construction for line larger than one-inch and constructed of corrosion-resistant material or coated * and cathodically protected. | NACE RP0169-2002 | Company engineering standards for piping and asset integrity management procedures are in accordance with industry standards. |
| (f) | Cathodic protection systems installed after December 30, 2008 are per industry standard and designed and installed by a corrosion expert **. | NACE RP0169-2002 | Cathodic protection on piping is not currently used. Company engineering standards for cathodic protection systems are consistent with industry standards. |
| (g) | Examination of exposed buried piping, and corrosion control and repair or replacement per (c) and (e) | API 570 ***<br>ASME B31.3-2004<br>ASME B31.4-2002<br>ASME B31.8-2003<br>NACE RP0169-2002 | Buried piping inspection and repair or replacement follows company engineering standards and asset integrity management procedures. |
| (h) | Buried metallic piping without cathodic protection is electrically inspected every three years, not exceeding 39 months and cathodic protection applied to areas of active corrosion per (d) or (f) | NACE RP0169-2002 | Buried piping without cathodic protection is inspected per company asset integrity management procedures. |
| (i) | Aboveground piping supported consistent with Paragraph 321 of ASME B31.3-2004. | ASME B31.3-2004 paragraph 321 | Piping support designs are consistent with ASME codes. |
| (j) | All piping maintained and inspected per API 570 ***. | API 570 *** | Inspection, maintenance, and repair procedures are in accordance with API 570. |
| (k) | Operation and maintenance of a cathodic protection system per NACE RP0169-2002 and must include survey by corrosion expert * or qualified cathodic protection tester *** and maintenance of test lead wires to determine system effectiveness. | NACE RP0169-2002 | Cathodic protection on piping is not currently used. Company engineering standards for cathodic protection systems are consistent with industry standards. |

| 18 AAC 75.080 | FACILITY OIL PIPING REQUIREMENT | INDUSTRY STANDARD | COPA MEASURE |
|---|---|---|---|
| (l) | Protection of aboveground piping from atmospheric corrosion using coatings * or consruction with corrosion-resistant material unless test, investigation, or experience determines corrosion will only be light surface ozide or not affect safe operation before program inspection. | (inspection program per API 570 ***) | Piping is subject to an inspection program in accordance with API 570. Experience shows that the ConocoPhillips inspection program is adequate to ensure safe operation. |
| (m) | Corrosion protection using protective coating * or construction with corrosion-resistant material for aboveground piping located at a soil-to-air interface. | None | Piping at soil-to-air interface has protective coating or is constructed of corrosion-resistant materials. |
| (n) | Routine visual inspection for leaks or damage, and damage protection for aboveground piping and valves | None | Company asset management practices include routine visual inspection of piping for leaks or damage, during normal operations. Vehicle barriers are in place, where appropriate. |
| (o) | "Removed from service" *** for more than one year must be free of oil, origin identified, and marked "Out of Service" with the date taken out of service and secured to prevent use. Notify ADEC. | None | Piping removed from service for more than one year is made free of oil and secured to prevent unauthorized use. Piping is marked "Out of Service" or "Removed from Service". Out-of-service notices are sent to ADEC on regular intervals. |

* Protective coating is defined in 18 AAC 75.080(p).

** Corrosion expert is defined in 18 AAC 75.990(169) and includes NACE certification or registered professional engineer.

*** API 570, Second Edition, October 1998, Addendum 1, February 2000, Addendum 2, December 2001, and Addendum 3, August 2003, excluding Section 8; adopted by reference (effective 12/30/2006, Register 180)

**** For purposes of this section, "removed from service" means not in regular use for the service intended and not included in a regular maintenance and inspection program.

### Below-Grade Facility Oil Piping

Although composed of non-corrosive stainless steel and encased in high density polyethylene pipe casing, the below-grade piping for the drag reducing agent tank is maintained under COPA's asset integrity program. The piping is operated under an ADEC compliance waiver of cathodic protection (CP) and protective wrapping/coating (see Section 2.6).

There are two buried lines at Alpine. These operate under an ADEC compliance waiver (see Section 2.6). The two buried lines are water lines to the WD-02 injection well and regulated pursuant to 18 AAC 75 due to the limited "oil" content in the fluids. The continued integrity of these lines are managed via an accelerated inspection program, as specified in the compliance waiver.

### Alpine Diesel Pipeline

The Alpine Diesel Pipeline is non-insulated and non-coated except at the Colville River crossing where it is cased . The diesel is not heated and the line operates at ambient temperature. Because the ambient temperature is below freezing during the majority of the year, external corrosion is anticipated to be limited. The pipe supports are in direct contact with the piping. A representative sampling of the pipe supports is inspected to determine external pipeline damage during each of the first five years the line is in operation and to verify that corrosion or mechanical damage in these areas is not a concern. Any damage found is recorded on a re-inspection schedule, and operations are modified, as practicable, to limit additional damage.

The diesel pipeline has dye added to diesel, and other products, when practical and as determined by Operations, in order to enhance visual monitoring for leak detection. Diesel pipelines are also monitored for any pressure loss during each transfer procedure.

### Flowlines and Facility Oil Piping Inspection

Flowlines and facility oil piping are routinely inspected to detect and prevent corrosion and leakage. The inspection programs are based on industry standards and best practices, and focus inspection efforts on areas of greatest potential for failure. Inspection and monitoring of flowlines and facility oil piping indicate if additional corrosion control is required, and provide feedback to success of the overall corrosion control program.

At a minimum, the intervals between flowline inspections meet the requirements of ASME B31.4-2002 for bare flowlines and API 570 for insulated flowlines.

Many factors determine the interval between successive inspections. Safety, history of the piping and similar-service piping, and state and federal regulations influence the frequency of inspections. Inspection and monitoring programs for internal and external corrosion use different methods, including the following:

- **Ultrasonic Inspection**. Ultrasonic techniques use acoustic waves to measure metal thickness and uniformity. Corrosion can be detected by changes in ultrasonic measurements. In addition to determining a baseline wall thickness, ultrasonic inspection can be used to determine changes in wall thickness with time. Specific locations are inspected and monitored for change with ultrasonic inspection accordingly.
- **Radiographic Inspection**. Radiographic inspection uses either gamma ray or X-ray sources to provide images of the metal, corrosion product, or insulation to aid in the assessment of asset condition. These techniques are useful in detecting metal loss to pipelines, both internal and external, and to assess the condition of the pipeline insulation and extent of corrosion product as a result of metal loss. In addition to providing a measure of the extent and depth of damage, radiographic inspection can be used to determine changes in damage with time. Specific locations are inspected with radiographic inspection periodically to monitor change.
- **Visual Inspections**. There are several forms of visual inspection. A detailed visual inspection is used when the surface to be inspected is accessed and cleaned for inspection. This technique may use pit depth gauges or ultrasonic techniques to aid in the evaluation of the asset's condition. The second type of visual inspection is the API 570 visual inspection for pipelines, which focuses on chafing, insulation damage, and pipeline support/structural integrity assessments. Visual inspections often entail ultrasonic inspection measurements along with visual observation of the piping.
- **Coupon Monitoring**. Metal coupons are strategically placed at designated locations to help assess the corrosiveness of the process fluid. The coupons are periodically removed, cleaned, and inspected to help evaluate corrosion potential of the system and to monitor corrosion inhibitor effectiveness. New coupons are then installed.
- **In-Line Inspection using "Smart pigs."** In-line inspections measure specific properties of the pipe as a function of length using pipeline pigs. The two most common instrumented pigs are "metal loss detection pigs" and "geometry pigs." Metal loss detection pigs are capable of evaluating locations with corrosion or gouges. Geometry pigs are used to identify dents and out-of-round conditions, as well as pipeline deflection, depending on the type of geometry pig

used. Flowlines capable of handling smart pigs are inspected with those pigs periodically, as determined by risk assessment.

- **Forward Looking Infrared (FLIR) System**. A FLIR system is an optical technology that uses the infrared spectrum to detect variations in temperature. COPA employs a hand-held device for localized investigation, or an aircraft-based system that allows surveillance of large areas. It is an effective tool for leak detection on the North Slope, since typically, the temperature of the process systems is different than the ambient (surrounding) temperature.

In addition, equipment and facilities at Alpine are maintained through the use of a computer-based Preventive Maintenance (PM) program that ensures the continued operational reliability of any flowline system component affecting quality, safety, and pollution prevention as required by 18 AAC 75.047(d)(2). The PM program was implemented to schedule maintenance at appropriate intervals to ensure equipment is fit for service. The program undergoes continual refinement by incorporating feedback from the field based on inspection results. In general, however, most corrosion inspections are driven by COPA's corrosion database, which may generate more frequent inspections than those scheduled by the PM program. Corrosion inspection records are kept and maintained in the database in accordance with API 570.

The PM program is comprehensive. Inclusion in this ODPCP of all inspections performed in conjunction with PM cycles for vessels, pipelines, containment areas and tanks is impractical because of the volume of written records. At scheduled intervals, these forms are generated by an automated PM information system located and accessed on site at Alpine. At the completion of the PM inspection cycle, the forms are reviewed for completion, and results and data entered for the particular equipment. This provides an historical record for each component. A review of proposed changes in pipeline operation to evaluate potential impacts on pipeline integrity is included as a task in the COPA Management of Change (MOC) procedure.

**Corrosion Control for Flowlines and Facility Oil Piping**

Applied corrosion control measures reflect the active or potential corrosion mechanisms in the relevant system. The corrosion mechanisms can be divided into internal mechanisms that vary with the service, and external mechanisms that are constant for all services.

COPA tracks spill events for corrosion-related leaks and spills and conducts one or more of the following:

- Root Cause Analysis,
- Physical Cause Analysis, or
- Latent Cause Analysis, as required by the situation.

If a spill occurs from piping due to corrosion, a survey of the area is conducted, including wall thicknesses, to determine the full extent of the affected area. Additionally, historical corrosion survey information for the area is reviewed in order to better understand and analyze the corrosion mechanisms and subsequent causes of the leak. Based on the results of these studies, a decision is made to either replace or repair the equipment. As applicable, other areas in the field operating with similar environments or histories are reviewed and surveyed to prevent similar spills or leaks from occurring. Inspection priorities are adjusted based on the outcome of such an analysis. In areas of concern, such as highly corrosive environments, corrosion inhibitors may be used, and surveys may be conducted more frequently to help identify and mitigate future occurrences.

Pipelines in corrosive service may be protected from corrosion by the following techniques when inspection or monitoring data indicate that adequate protection does not exist:

- Internal Corrosion Control Techniques:
  - **Corrosion Inhibitors**. Chemical corrosion inhibitors are used to continuously coat the inside of pipelines or to inhibit chemical corrosivity of the produced fluids.
  - **Biocide**. Biocide is used to prevent growth of bacteria within the oil production and water system.
  - **Pigging**. Seawater pipelines, produced water pipelines, and some production pipelines are routinely pigged to remove scale and deposits that can allow corrosion to occur. Pigging can allow corrosion inhibitors to work more effectively by providing a clean surface.
- External Corrosion Control Techniques:
  - **Coating**. Coating with polymeric materials is used to protect the steel from corrosive fluid. These polymeric materials provide a barrier between the metal and fluid.
  - **Maintenance Procedures for Pipe Casings**. Pipe casings under road crossings are inspected annually for the presence of soil and debris that may be in contact with piping. When encountered, the soil and debris are removed to reduce the potential for external corrosion.

Weight-loss corrosion coupons from the various process streams are examined periodically, based on the historical corrosivity of a system. The frequency is typically between three months and one year. The frequency of coupon examination in specific locations is determined by a qualified corrosion engineer and adjusted over the life of the field to provide adequate process monitoring.

Monitoring locations are selected where water is present or may be present during process upsets, and where corrosion has been seen in other operating fields. Corrosion coupon fittings are strategically placed throughout the production, miscible injection, and seawater in-field pipeline system at Alpine.

When necessary, corrosion inhibitor is injected at well site manifolds and at the inlet separator. Injection rates vary with results from the corrosion inspection program.

**Leak Detection**

The flowlines at Alpine use pipeline pressure/flow monitoring and visual inspection as the primary methods for leak detection. Three-phase production fluid pipelines contain low-pressure switches that automatically shut in the pipeline upon detection of a significant leak or line rupture. Monitoring for small leaks is accomplished primarily by visual inspection during routine visits to production pads. Routine overflights, FLIR, or ground-based visual examinations of the piping also may be used for early leak and spill detection. In addition, flowlines to CD3 are visually inspected by routine aerial surveillance during periods when an ice road is not in place.

## 2.1.8 Leak Detection, Monitoring, and Operating Requirements for Crude Oil Transmission Pipelines [18 AAC 75.055]

For the Alpine Oil Pipeline, metered volume balancing is performed at least once every 24 hours using measurements by flow meters at CD1 and at the Alpine Oil Pipeline terminus at Kuparuk CPF2, as required

by 18 AAC 75.055(a)(2). Flow measurements are continuously monitored via the Supervisory Control and Data Acquisition (SCADA) system and managed by control room board operators.

Computational pipeline monitoring is the primary means of providing continuous leak detection capability, as required by 18 AAC 75.055(a)(1). The Alpine Pipeline System is equipped with a software system capable of detecting a leak having a daily rate equal to one percent of daily throughput. The flow of incoming oil can be stopped within one hour after detection of a spill, as required by 18 AAC 75.055(b). In the event of an alarm, the control board operator proceeds through a series of steps to determine its cause. Aerial or ground-based surveillance may be requested. The leak detection system details are presented in Section 2.5.2 and Section 4.11.

If a spill is detected, the pipeline will be shut down. The shut down will prevent or mitigate a substantial threat of a worst case discharge. If the ESD system fails, the pipeline would be manually shut down by on-site personnel. Manual shutdown valves are located inside at the Alpine processing facility and at Kuparuk CPF2. These facilities are staffed 24 hours a day.

The Alpine Oil Pipeline is considered a remote pipeline because it is not always directly accessible by ground transportation. For a remote pipeline, 18 AAC 75.055(a)(3) requires weekly visual inspections to be made by aerial surveillance. The goal of these aerial surveys is visual detection of oil slicks that may develop as a result of an oil leak below monitoring thresholds. COPA conducts weekly visual aerial surveillance to meet requirements of 18 AAC 75.055(a)(3).

Natural events such as flooding, ice damage, or frost jacking could impact facilities and pipelines. Should any of these events pose a threat, visual evaluations will be performed to determine if a line or facility should remain in operation. Each DOT-regulated Alpine pipeline has an operations manual that addresses all operations and procedures related to the pipeline, including abnormal and emergency operations.

COPA notifies ADEC in writing within 24 hours if a significant change is made to, or occurs in, the leak detection system and if, as a result of the change, the system no longer meets the ADEC performance requirements in 18 AAC 75.055, as required by 18 AAC 75.475.

<u>Horizontal Directional Drilling Belowground Pipeline Section</u>

The leak detection systems that apply to the aboveground pipeline also apply to the belowground section. In addition, the annular space in the casing at the Colville River horizontal directional drilling crossing is equipped with a conduit for leak detection sensors. The sensors are able to detect fluids entering the annular space.

The technology uses a small sensor that measures the refraction of light through liquids. Each liquid has a different index of refraction, allowing the sensor to distinguish between oil and water, and the sensor is sensitive enough to distinguish between different types of hydrocarbons. Fiber optic cable connects the sensor to the control panel and carries light between the two. The system is inherently safe because no electrical power is used in the annulus. The sensor automatically resets and does not require removal after wetting.

### 2.1.9 Shop Fabricated Aboveground Oil Storage Tanks [18 AAC 75.066]

Section 3.1.2 contains additional information on the ADEC-regulated oil storage tanks at Alpine. There are currently no field-constructed oil storage tanks at Alpine placed into service after December 30, 2008; as such, requirements at 18 AAC 75.065 for field-constructed aboveground oil storage tanks do not apply. The

following addresses requirements of 18 AAC 75.066 for ADEC-regulated shop-fabricated aboveground oil storage tanks at Alpine.

### Tank Design and Construction

In accordance with 18 AAC 75.066(a)(1), ADEC-regulated shop-fabricated aboveground oil storage tanks initially placed into service on or before December 30, 2008, are not subject to requirements for design and construction standards and, if of vaulted, self-diked, or double-walled design, are not subject to additional design and equipment requirements of 18 AAC 75.066(c), (d), and (e), respectively.

ADEC-regulated shop-fabricated aboveground oil storage tanks placed into service after December 30, 2008, will be consistent with 18 AAC 75.066(a)(2). Tanks placed into service after December 30, 2008, will be designed and constructed according to an ADEC-approved design, including: Underwriters Laboratory (UL) 142, API 650, API 12F, STI F921-03, UL 2085, or an engineer-certified design approved by ADEC. ADEC-regulated vaulted, self-diked, or double-walled shop-fabricated aboveground oil storage tanks placed into service after December 30, 2008, will meet requirements of 18 AAC 75.066(c), (d), and (e), respectively.

### Maintenance and Inspection

Regulated oil storage containers owned and operated by COPA are maintained and inspected in accordance with state and federal regulatory requirements. Required inspections, repairs, and alterations are discussed in the following sections. Inspection schedule information for ADEC-regulated tanks is provided in Appendix D, Table D-1 for tanks owned by COPA and operated at Alpine, in Table D-2 for tanks owned by COPA that may be operated at Alpine, in Table D-3 for tanks that may be directly rented by COPA, and in Table D-4 for third-party tanks not owned or leased by COPA. Descriptions and locations of oil storage containers with capacity less than 10,000 gallons and that are regulated by EPA, are listed in COPA's Alpine SPCC Plan. EPA SPCC-regulated oil containers, with capacity of 55 gallons or more, are inspected in accordance with COPA tank management and/or PM programs, which include periodic visual inspection conducted according to written procedures. Additional description, locations, and inspection information is provided in COPA's Alpine SPCC Plan available at the facility.

COPA requires regulated tanks rented or leased directly by COPA meet all applicable regulatory requirements.

ADEC-regulated oil storage tanks at Alpine are elevated. Internal and external inspections on regulated tanks are performed by a tank inspector certified under API 653 at the frequencies required by API 653 and 18 AAC 75.066(f), or as determined by the certified inspector under best management practices.

COPA inspects and maintains tanks in accordance with tank management and PM programs. Tanks not owned, leased, or operated by COPA (otherwise referred to as third-party tanks) are inspected and maintained by the tank owner. COPA may audit third-party service companies to ensure their practices are in accordance with their respective tank management programs. Tanks provided by non pre-qualified companies are reviewed by COPA prior to being put into service.

Integrity inspection of aboveground oil storage tanks is conducted by staff or contract-certified tank inspectors in accordance with API 653 and ADEC requirements for regulated tanks.

Internal tank corrosion is often mitigated by use of coatings, anodes (cathodic protection), and/or the use of corrosion-resistant alloys.

At a minimum, monthly routine operational examinations (external) are conducted for ADEC-regulated oil storage tanks. EPA SPCC-regulated oil storage containers are visually inspected at least annually. Written records of repairs or operational alerts are retained for the life of the tanks. Records of API 653 inspections are prepared according to API document guidelines and retained for the service life of the tanks. Records of visual inspections are maintained in accordance with Company policies.

**Discharge Prevention**

For tanks with automated liquid level devices, various types of liquid level devices are used for overfill protection and tank level indication. For some tanks at CD1, devices feed into the distributed control system (DCS) for localized control of shutdown and/or alarms, with reporting back to the control room. If a high-level situation is detected, the transmitters send a signal to the DCS, which initiates both remote and local alarms and closes automated ESD valves on those tanks that are so equipped. The ESD valves are automated valves.

The three types of liquid level devices are:

- **Hydrostatic Head or Differential Pressure Devices:** These transmitters are located in the bottom of the tank and measure the liquid level by comparing atmospheric pressure and the pressure inside of the tank.
- **Ultrasonic Non-Contact Transmitter:** This transmitter utilizes microprocessor-based electronics and non-contact ultrasonic transducers to provide a level measurement unaffected by changes in specific gravity, viscosity, or conductivity. The sensor is mounted at the top of the tank. Ultrasonic pulses are directed to the measuring surface. The returning echo is detected by the sensor, and the electronics amplify and convert the signal into a digital representation of the level.
- **Microwave Radar Non-Contact Transmitter:** This transmitter utilizes microwave signals, typically emitted from an antenna, that travel at light velocity to the liquid surface and then are reflected back to a sensor that detects the time taken for the microwave reflection (or echo). Unlike sound waves, microwaves require no transmission medium and can be applied in vacuum and positive-pressure conditions.

At a minimum, monthly manual tank strapping measurements are conducted on non-fuel gas-blanketed tanks or tanks without two independent level measurement devices to check tank levels and verify automated devices indicate proper level limits.

Tanks with more than one independent transmitter have additional (redundant) protection. The independent systems are measured for deviations between each other. Audible systems connected to the DCS will sound an alarm in the control room if deviations are detected. This type of backup system creates a continuous internal testing system for the liquid-level devices.

Overfill protection devices are tested before each transfer operation, or monthly, whichever is less frequent. If monthly testing would necessitate interrupting the operation of a system subject to continuous flow, monthly inspection and annual testing may be substituted for the monthly testing as required in 18 AAC 75.066(h). For tanks without automated overfill protection devices, overfill protection relies on visual surveillance. Tank fuel levels are monitored and controlled manually during filling activities.

Fueling operations will follow COPA's fuel transfer procedures to prevent discharge from transfer hoses, as discussed in Section 2.1.5.

## 2.1.10 Secondary Containment Areas for Aboveground Oil Storage Tanks [18 AAC 75.075]

For purposes of 18 AAC 75.075, 18 AAC 75.990(165) defines "aboveground oil storage tank" as having capacity of greater than 10,000 gallons. Secondary containment is provided at permanent tank installations and for regulated oil storage containers, according to applicable requirements. Secondary containment areas for aboveground oil storage tanks are sufficiently impermeable, typically lined with a product resistant synthetic liner and sized for 100 percent capacity of the largest single tank, plus an additional volume for precipitation. Secondary containment information including type and volume descriptions for EPA SPCC-regulated oil storage containers with capacity 55 gallons or greater as required by 40 CFR 112.7(c), and 112.8(c), or 112.9(c), is provided in the Alpine SPCC Plan.

Secondary containment systems are resistant to operational damage and weather, and are sufficiently impermeable as required by 18 AAC 75.075(a)(2). In addition, personnel follow a field procedure, which describes the containment dimensions based on the size and number of tanks when constructing secondary containments for portable tanks. Secondary containment systems are maintained free of major debris, vegetation, and excessive accumulated water that may interfere with the effectiveness of the system. Secondary containment areas are routinely visually checked for presence of leaks or spills and documented weekly inspections are performed, in accordance with 18 AAC 75.075(c). Drainage, when required to recover containment capacity due to snowmelt or rain, is typically performed by vacuum truck. Where applicable, COPA's Liner and Drip Pan Use Policy will be followed..

Shop-fabricated aboveground oil storage tanks of a vaulted, self-diked, or double-walled design are not required by state or federal regulation to be placed within bermed, lined, secondary containment areas if they are equipped with catchments that positively hold overflow due to tank overfill, or divert it into an integral secondary containment area [18 AAC 75.075(h)]. Local agency requirements for containment of double-walled tanks are either met or waived by approval of the local agency.

Portable oil storage tanks that are temporarily not in use are emptied and placed within designated storage areas on gravel pads without secondary containment. The stored tanks are maintained under the tank management program.

COPA notifies ADEC in writing within 24 hours if a significant change occurs in or is made to an ADEC-regulated secondary containment system and if, as a result of the change, the system no longer meets the ADEC performance requirement [18 AAC 75.475(d)].

### Tank Truck Loading Areas and Permanent Unloading Areas

For purposes of compliance with 18 AAC 75.075(g), tank truck loading areas and permanent unloading areas are identified in Table 2-3 and are recognized as those involving frequent transfers of oil to and from ADEC-regulated aboveground oil storage tanks, which is defined in 18 AAC 75.990(165).

In accordance with 18 AAC 75.075(g), tank truck loading areas and permanent unloading areas are:

- Designed with secondary containment to contain 100 percent of the maximum capacity of any single compartment of a tank truck;
- Paved, surfaced, or lined with sufficiently impermeable materials;
- Maintained free of debris, vegetation, excess accumulated water, or other materials;

- Have warning lights, warning signs, or contain physical barriers to prevent premature vehicular movement; and
- Visually inspected before any transfer operation, or at least monthly.

## TABLE 2-3:TANK LOADING AND UNLOADING AREAS AT ALPINE

| FACILITY | MODULE | TAG # | SERVICE | NOMINAL DESIGN CAPACITY (BBL) | MAXIMUM BULK TRUCK COMPARTMENT SIZE (BBL) | BULK TRUCK AREA LINED? (Y/N) | LINER TYPE | SIZE/CAPACITY OF LINED AREA FOR BULK TRUCKS | BERMS, TRENCHES, OR DRAINS FOR LOADING AREA CONTAINMENT | PHYSICAL BARRIERS, LIGHTS, OR SIGNS | WAIVERS IN EFFECT |
|---|---|---|---|---|---|---|---|---|---|---|---|
| CD1 | G1 | CF-T-50061A | Completions Fluid Storage Tank (Diesel at present) | 400 | 325 | Y | Pre-cast concrete slabs with underlying geomembrane liner (80-mil Polyshield SS-100 or equivalent) | 95 ft X 36.3 ft<br>620 bbl | 4% grade toward a sump with vertical sidewalls, slopes up again at opposite end; pre-cast curbs along the sides; sump at bottom | Yes | None |
| | G1 | CF-T-50061B | Completions Fluid Storage Tank (Diesel at present) | 400 | | | | | | | |
| | G1 | CF-T-50063A | Upright Fiberglass Tank ("Brine Tank") (Diesel at present; may also contain mineral oil or brine) | 400 | | | | | | | |
| | G1 | CF-T-50063B | Upright Fiberglass Tank ("Brine Tank") (Diesel at present; may also contain mineral oil or brine) | 400 | | | | | | | |
| | G1 | CF-T-61001 | ULSD Storage Tank | 3,300 | | | | | | | |
| | G2 | CF-T-50031 | Production Chemical Tank (Biocide) | 250 | | | | | | | |
| | G2 | CF-T-50011 | Production Chemical Tank (Scale Inhibitor) | 400 | | | | | | | |
| | G2 | CF-T-50001 | Production Chemical Tank (Emulsion breaker) | 750 | | | | | | | |
| | G2 | CF-T-60001 | Lube Oil Storage Tank | 250 | | | | | | | |
| | G2 | CF-T-31010 | Slop Oil Tank | 1,500 | | | | | | | |
| | G2 | CF-T-52001 | Production Chemical Tank (Triethylene glycol) | 250 | | | | | | | |
| | G2 | CF-T-51001 | Production Chemical Tank (dry crude or diesel) | 1,500 | | | | | | | |
| | G5 | CF-T-50090 | Glycol or Diesel | 803 | | | | | | | |
| | G6 | CF-T-50120 | Corrosion Inhibitor | 750 | | | | | | | |
| | Alpine Injection Skid (MI SWACO) | MI-A6061610 | Varies – water and drilling mud | 1,000 | 325 | Y | Sufficiently impermeable welded steel structure | 86 ft X 25 ft<br>approx. 473 bbl | Below grade, drive through area with containment sump tanks | Yes | |
| | | MI-A6061611 | Varies – water and drilling mud | 1,000 | | | | | | | |
| | | MI-A6061612 | Varies – water and drilling mud | 1,000 | | | | | | | |
| | | MI-A6061613 | Varies – water and drilling mud | 1,000 | | | | | | | |
| CD2 | CD2 Tank Farm | CD2-T-51001 | Weathered crude Storage Tank | 500 | 325 | Y | Pre-cast concrete panels with underlying geomembrane liner | 85.6 ft X 23.6 ft<br>635 bbl | 3% grade toward sump, slopes up at opposite end; pre-cast curbs along the sides | Yes | None |
| | CD2 Tank Farm | CD2-T-50011 | MeOH | 250 | | | | | | | |
| CD3 | CD3 J | CD3-T-383003 | Hydrocarbon recycle | 443 | 325 | Y | Pre-cast concrete panels and curbing with underlying geomembrane liner | 81.5 ft X 16.5 ft<br>350 bbl | 2% grade toward sump, slopes up at opposite end; pre-cast curbs along the sides | Yes | None |
| | CD3 J | CD3-T-553003 | Water recycle | 443 | | | | | | | |
| | CD3 J | CD3-T-613012 | ULSD Storage Tank | 252 | | | | | | | |
| | CD3 J | CD3-T-513006 | Methanol | 443 | | | | | | | |
| | CD3 J | CD3-T-503009 | Corrosion Inhibitor | 443 | | | | | | | |
| | CD3 J | CD3-T-503010 | Scale Inhibitor | 136 | | | | | | | |
| | CD3 J | CD3-T-503037 | Biocide | 25 | | | | | | | |
| | CD3 J | CD3-T-503038 | Oxygen Scavenger | 25 | | | | | | | |
| | CD3 J | CD3-T-503011 | Anti-foam | 136 | | | | | | | |
| | CD3 J | CD3-T-503012 | Emulsion Breaker | 136 | | | | | | | |
| | CD3 J | CD3-T-503013 | Vehicle fuel day tank | 12 | | | | | | | |
| CD5 | Chemical Tank Farm CD5Q | CD5-T-505031 | Weathered crude | 847 | 325 | Y | Pre-cast concrete panels and curbing with underlying geomembrane liner and lined secondary containment sump | (containment sump)<br>67 ft X 16.6 ft X 2.42 ft<br>338 bbl | 1% slope from tank truck area toward containment sump | Yes | None |
| | | CD5-T-505002 | Corrosion Inhibitor (non-oil) | 847 | | | | | | | |
| | | CD5-T-505044 | Corrosion Inhibitor (non-oil) | 847 | | | | | | | |

BLANK PAGE

## 2.2 DISCHARGE HISTORY [18 AAC 75.425(e)(2)(B)]

Alpine participates proactively in spill prevention programs including campaigns, investigations, and training to increase employee awareness levels.

The major causes for oil spills greater than 55 gallons were equipment difficulties associated with tanks, which accounts for most spills since 1999. Causes for spills can be grouped in the following categories:collision, corrosion, equipment failure, human error, leak, overfill, and unknown (Table 2-4).

**TABLE 2-4: ALPINE OIL SPILL REPORTS (1999-2016)**

| CAUSE CATEGORY | CAUSE | SOURCE | NUMBER OF SPILLS | ESTIMATED CUMULATIVE VOLUME (GAL) |
|---|---|---|---|---|
| Human Factors | Human Error | Fittings/seals/connections | 1 | 440 |
| | | Heavy Equipment/ Mobile Equipment/ Vehicles | 2 | 664 |
| | | Tanks | 4 | 913 |
| | Overfill | Heavy Equipment/ Mobile Equipment/ Vehicles | 2 | 151 |
| | | Tanks | 3 | 3,551 |
| Structural/Mechanical | Collision | Heavy Equipment/ Mobile Equipment/ Vehicles | 1 | 600 |
| | Corrosion | Pipe/flowlines/ hardlines | 1 | 170 |
| | Equipment Failure | Flanges | 1 | 1,560 |
| | | Tanks | 4 | 485 |
| | | Transfer hoses | 1 | 420 |
| | Leak | Coiled tubing unit/wireline equip/well service | 1 | 62 |
| | | Fittings/seals/connections | 1 | 252 |
| | | Sumps | 1 | 500 |
| | | Tanks | 1 | 210 |
| | Overfill | Fittings/seals/connections | 1 | 840 |
| Operational | Unknown | Flares | 1 | 210 |
| | | Pipe/flowlines/ hardlines | 1 | 137 |

The history of known discharges of volumes greater than 55 gallons is maintained in the COPA spill database for the life of the facility. The database includes the source, cause, amount of the discharge, and corrective actions taken. Most spills that occur at Alpine are small events that are contained on gravel pads and rarely reach the tundra or water environment. The history of known discharges greater than 55 gallons for COPA in the Alpine field since 1999 is included in Appendix C.

A spill analysis was completed for oil spills over 55 gallons at Alpine since facility startup in 1999 through 2016. The analysis showed that sources with the highest percentage of spill incidents were tanks (44%) and heavy equipment/ mobile equipment/ vehicles (18%) (Figure 2-1). The largest percentage of spill volume was from tanks (46%), and from flange failure (14%) and heavy equipment/ mobile equipment/ vehicles (13%) (Figure 2-2). Figure 2-3 illustrates percentage of oil spill volume by cause.

The history of known discharges for reportable spills to tundra and/or water since 1999 is included in Appendix A. Appendix A includes the information outlined in 40 CFR Part 112, Appendix F, Section 1.4.4, for spills that are identified by 40 CFR Part 110.

COPA North Slope operations employ several measures to minimize and mitigate the occurrence of spills. A "Root Cause Failure Analysis" investigation process occurs for significant spills and corrective actions are taken based on the analysis by the review team. Lessons learned are shared with supervisors and affected workgroups to promote spill prevention. Depending on the incident, the review team may include: personnel responsible for the operation causing the spill, their foreman or supervisor, a safety representative, field environmental compliance personnel, a facility supervisor, and/or a corrosion engineer. The investigation process is aimed at increasing safety and reducing personnel exposure to spilled materials, preventing reoccurrence of spills, and identifying spill causes and early detection. Spill investigation results are communicated to field personnel to promote spill prevention. Periodically, teams may be developed to conduct an analysis of spill causes, volumes, and frequencies. Slope-wide trends of frequency, cause, and size of spills are noted.

COPA promotes spill prevention by encouraging proactive involvement and knowledge sharing through spill prevention programs and awareness training or communications. Personnel receive recognition for outstanding spill prevention and information or new tools/procedures are shared with other Alpine personnel.

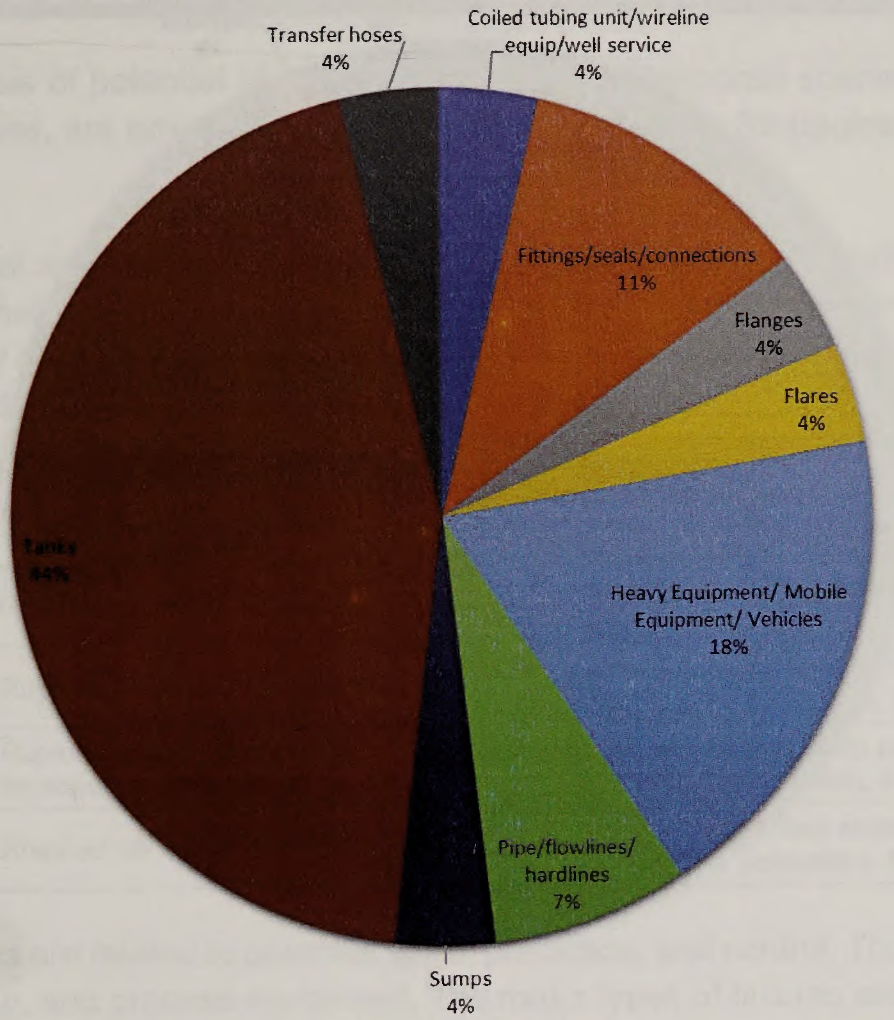



**FIGURE 2-1: PERCENTAGE OF OIL SPILL INCIDENTS BY SOURCE (1999 – 2016)**

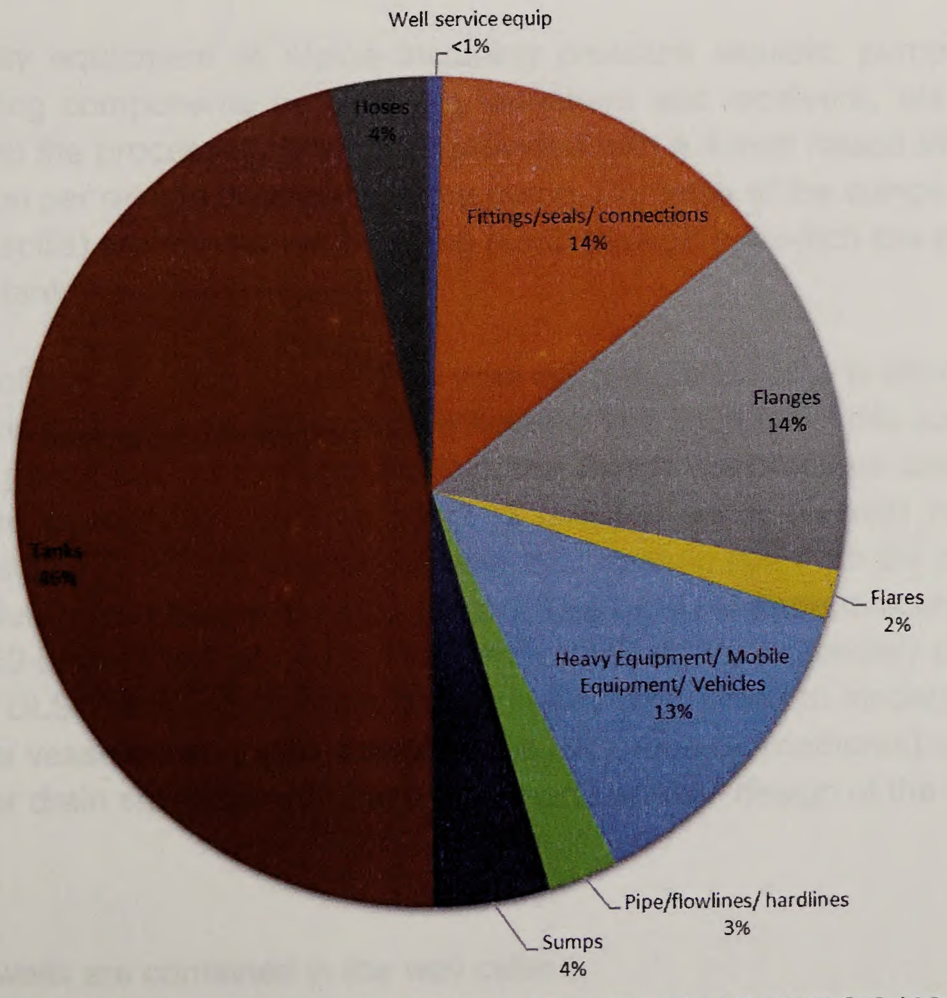



**FIGURE 2-2: PERCENTAGE OF OIL SPILL VOLUME BY SOURCE (1999 – 2016)**

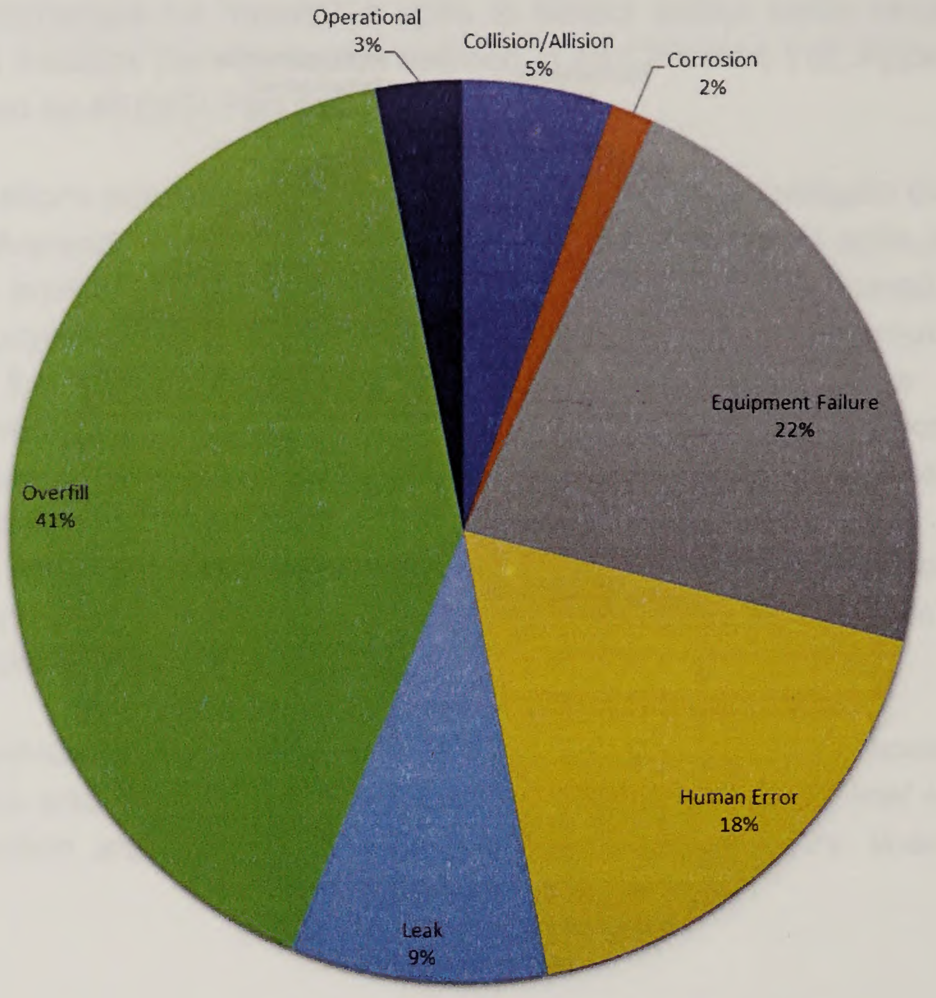



**FIGURE 2-3:PERCENTAGE OF OIL SPILL VOLUME BY CAUSE (1999 – 2016)**

## 2.3 POTENTIAL DISCHARGE ANALYSIS [18 AAC 75.425(e)(2)(C)]

This section is an analysis of potential oil discharges at Alpine. Response scenarios, including response planning standard volumes, are presented in Section 1.6.3, Response Strategies, and are not duplicated here.

Table 2-5 shows potential spill sources, the types of failures that may occur, estimates of spill sizes, and appropriate prevention measures for Alpine operations. The historical data presented in Section 2.2 assist in identifying the areas of operation prone to spills. Table 2-6 indicates the approximate calculated volumes of individual pipeline sections.

**TABLE 2-5: ALPINE POTENTIAL OIL SPILLS FROM MAJOR SOURCES**

| SOURCE | CAUSE | SIZE | PREVENTION MEASURES |
|---|---|---|---|
| ULSD Storage Tank | Rupture, overflow, valve leak | 3,300 bbl | Impound basin, overfill alarms, daily visual checks |
| Portable Tank | Rupture, overflow, valve leak | 400 bbl (varies) | Secondary containment, transfer procedures, overfill alarms |
| Fuel Transfer | Rupture, overfill, valve leak, improper procedures | 5 bbl | Liners/drip pans, visual integrity inspection, transfer procedures |
| Production Well | Sheared off | 2,000 –10,000 bbl/day | surface safety valves, blowout preventers, ESD system |

The following discussions are related to potential spills, prediction, and control. The major source of failures are tanks, vessels, piping, and process equipment. The major types of failures are leaks or ruptures.

### Alpine Central Processing Facility

Major process and utility equipment at Alpine including pressure vessels, pumps, gas compressors, heaters, and major piping components such as pig launchers and receivers, are housed in enclosed modules. The modules in the processing facility are provided with a 4-inch raised sill and a module sump equipped with a 30-gallon per minute pneumatic sump pump. Contents of the sumps (resulting from minor hydrocarbon and water spills) are transferred by sump pump through a six-inch low-pressure drain header to the 1,500-barrel slop tank.

In case of a major loss of containment, the overflow from each module sump is directed to the 660-gallon open-drain overflow sump through a six-inch overflow header. The contents of this sump are transferred by a 30-gallon per minute pneumatic sump pump through the 6-inch low-pressure drain header to the slop tank. Overflow from the open-drain overflow sump is directed via a six-inch line to the secondary containment basin in the tank farm. The largest possible hydrocarbon spill from the process area (the inlet separator in the A3 module) will not exceed 1,000 barrels. The ULSD storage tank and other storage tanks are contained by a 5,220-barrel lined pit and a dike. The volume of the secondary containment is greater than 100 percent of the ULSD tank, which is the largest facility tank. Small to moderate leaks from failures of bulk chemical tanks or vessels (i.e., crude, corrosion inhibitor, lube oil, methanol) within the facility would be controlled by the floor drain sump system and by the modular "cell" design of the facility itself.

### Drill Sites

Small discharges from wells are contained in the well cellars.

In the event of an on-pad rupture or failure, a discharge is typically retained by the gravel pad. Personnel are summoned for spill response and containment as described in Section 1. In the event of a flowline

rupture or failure, subsurface and/or surface safety valves in the well are activated to a closed position from a low-pressure sensor, preventing continued discharge. Low-pressure alarms alert Operations personnel who would initiate spill response and containment, as necessary.

Production and gas injection wells at Alpine are subject to routine integrity testing by AOGCC statutes. On a rotating basis, each well is subject to testing on a frequency determined by well type. The safety systems of the well being tested are tripped out by an artificially-created low-pressure signal which causes the safety valves to shut in the well. A manual valve downstream is then closed and the tubing pressure is observed for increases in pressure. The State of Alaska inspectors witness the successful testing of the wellhead safety systems at prescribed intervals for wells capable of flowing hydrocarbons.Annulus integrity of injection wells is tested by a COPA procedure. The State of Alaska inspectors also witness this testing.

**Pipelines**

In the event of pipeline failure, Operations personnel isolate the damaged section by closing the necessary valves to prevent further discharge from production or backflow potential. The backflow potential is further reduced by the vertical loops along the crude oil transmission pipeline and diesel pipeline.

Reaction time to isolate pipeline sections varies and is a factor in predicting spill volume potential. It is difficult to predict the rate or spill potential for any given pipeline beyond the immediate volume of the affected pipeline. Continuous production from drill sites is stopped when low pressure is sensed as a result of the failure. Both the visual observation of a pipeline leak by field personnel, and the low-pressure alarms from the primary separator vessel sensors, initiate a response and shut-in. It is unlikely that the entire volume would be drained, due to the frequent elevation changes associated with routing of pipelines and/or vertical loops.

In the event of a pipeline spill, natural depressions adjacent to the subject pipeline and nearby dry lakebed depressions will provide temporary containment. Spill response will be provided by the Alpine SRT and/or COPA's primary response action contractor, according to the procedures described in Section 1.

Seawater pipelines have been included in the response planning effort even though seawater is not hydrocarbon by nature. It is unlikely that seawater pipelines, should they require displacement for freeze protection in the event of upset, will be displaced with any substance other than warm fuel gas. However, a portion of the displacement process requires a glycol/water "slug" to chase the water from the pipeline, leaving a glycol residue that coats the pipeline wall. Should a failure occur during this process, glycol may be present in the seawater.

Should a spill occur from a produced water pipeline, hydrocarbons may be present and should be considered in the spill response.

Drainage maps of the Alpine area are located in the ACS *Technical Manual* Map Atlas and Section 1.8.

## TABLE 2-6: POTENTIAL DISCHARGE OF ALPINE PIPELINES

| FROM | TO | DIAMETER* (IN) | LENGTH (FT) | PIPELINE CAPACITY ($FT^3$) | POTENTIAL DISCHARGE (BBL) | NOTE |
|---|---|---|---|---|---|---|
| **SALES CRUDE OIL** | | | | | | |
| CD1/ACF | HDD West Loop | 14 | 47,886 | 51,191 | 9,112 | |
| HDD West Loop | HDD East Loop | 14 | 5,304 | 5,670 | 1,009 | Colville River crossing (below grade) |
| HDD East Loop | Vertical Loop #1 | 14 | 8,951 | 9,569 | 1,703 | |
| Vertical Loop #1 | Vertical Loop #2 | 14 | 42,413 | 45,340 | 8,071 | |
| Vertical Loop #2 | Vertical Loop #3 | 14 | 1,255 | 1,342 | 239 | Kachemach River crossing |
| Vertical Loop #3 | Vertical Loop #4 | 14 | 18,809 | 20,107 | 3,579 | |
| Vertical Loop #4 | Vertical Loop #5 | 14 | 3,317 | 3,546 | 631 | Miluveach River crossing |
| Vertical Loop #5 | CPF2 Valve | 14 | 54,741 | 58,519 | 10,416 | |
| **PRODUCED OIL (THREE PHASE LIQUID)** | | | | | | |
| CD1 | CD1/ACF | 18 | 790 | 1,396 | 248 | |
| CD2 | CD1/ACF | 20 | 17,600 | 38,397 | 6,835 | |
| CD3 | CD1/ACF | 16 | 35,800 | 49,986 | 8,898 | |
| CD4 | CD1/ACF | 14 | 23,600 | 25,229 | 4,491 | |
| CD5 | CD5 Nigliq Valve | 20 | 16,646 | 36,316 | 6,464 | |
| CD5 Nigliq Valve | CD5@ CD4 road | 20 | 19,453 | 42,440 | 7,554 | |
| CD5@ CD4 road | CD1/ACF | 20 | 15,285 | 33,347 | 5,936 | |
| GMT1 | West Tin Valve | 19.25 | 30,414 | 61,470 | 10,942 | |
| West Tin Valve | East Tin Valve | 19.25 | 3,285 | 6,639 | 1,182 | Tinmiaqsiugvik River crossing |
| East Tin Valve | CD1/ACF | 19.25 | 11,090 | 22,414 | 3,990 | |
| **ENHANCED OIL RECOVERY (MISCIBLE INJECTANT)** | | | | | | |
| CD1/ACF | CD1 | 6 | 790 | 155 | 28 | |
| CD1/ACF | CD2 | 8 | 17,600 | 6,144 | 1,094 | |
| CD1/ACF | CD3 | 6 | 35,800 | 7,029 | 1,251 | |
| CD1/ACF | CD4 | 6 | 23,600 | 4,634 | 825 | |
| CD1/ACF | CD5 | 6 | 51,384 | 10,089 | 1,796 | |
| CD5 | GMT1 | 7.5 | 44,600 | 13,683 | 2,436 | |

| FROM | TO | DIAMETER* (IN) | LENGTH (FT) | PIPELINE CAPACITY ($FT^3$) | POTENTIAL DISCHARGE (BBL) | NOTE |
|---|---|---|---|---|---|---|
| **SEAWATER** | | | | | | |
| CPF2 Valve | Vertical Loop #5 | 12 | 54,741 | 42,993 | 7,653 | |
| Vertical Loop #5 | Vertical Loop #4 | 12 | 3,317 | 2,605 | 464 | Miluveach River crossing |
| Vertical Loop #4 | Vertical Loop #3 | 12 | 18,809 | 14,773 | 2,630 | |
| Vertical Loop #3 | Vertical Loop #2 | 12 | 1,255 | 986 | 175 | Kachemach River crossing |
| Vertical Loop #2 | Vertical Loop #1 | 12 | 42,413 | 33,311 | 5,929 | |
| Vertical Loop #1 | HDD East Loop | 12 | 8,951 | 7,030 | 1,251 | |
| HDD East Loop | HDD West Loop | 12 | 5,304 | 4,166 | 742 | Colville River crossing (below grade) |
| HDD West Loop | CD1/ACF | 12 | 47,886 | 37,610 | 6,695 | |
| CD1/ACF | CD1 | 8 | 790 | 276 | 49 | |
| CD1/ACF | CD2 | 10 | 17,600 | 9,599 | 1,709 | |
| CD1/ACF | CD3 | 8 | 35,800 | 12,497 | 2,224 | |
| CD1/ACF | CD4 | 8 | 23,600 | 8,238 | 1,466 | |
| CD1/ACF | CD5 | 8 | 51,384 | 17,936 | 3,193 | |
| CD1/ACF | CD5 | 12.75 | 51,600 | 45,751 | 8,144 | |
| CD5 | GMT1 | 12.75 | 44,600 | 39,544 | 7,039 | |
| **DIESEL** | | | | | | |
| CPF2 Valve | Vertical Loop #5 | 2 | 54,741 | 1,194 | 213 | |
| Vertical Loop #5 | Vertical Loop #4 | 2 | 3,317 | 72 | 13 | Miluveach River crossing |
| Vertical Loop #4 | Vertical Loop #3 | 2 | 18,809 | 410 | 73 | |
| Vertical Loop #3 | Vertical Loop #2 | 2 | 1,255 | 27 | 5 | Kachemach River crossing |
| Vertical Loop #2 | Vertical Loop #1 | 2 | 42,413 | 925 | 165 | |
| Vertical Loop #1 | HDD East Loop | 2 | 8,951 | 195 | 35 | |
| HDD East Loop | HDD West Loop | 2 | 5,304 | 116 | 21 | Colville River crossing (below grade) |
| HDD West Loop | CD1/ACF | 2 | 47,886 | 1,045 | 186 | |
| CD1/ACF | CD3 | 2 | 35,800 | 781 | 139 | |

*GMT1 pipelines potential discharge estimated using inner diameter size; other pipeline's diameter sizes may reflect outer shell measurement and thus provide more conservative potential discharge volume estimates.

## 2.4 CONDITIONS INCREASING RISK OF DISCHARGE [18 AAC 75.425(e)(2)(D)]

Conditions specific to COPA's North Slope operations that potentially increase the risk of discharge, and actions taken to eliminate or minimize identified risks, are summarized below:

- **Temperature:** Heat may cause gases to expand, increasing the likelihood of discharge. North Slope facilities are engineered to accommodate temperature fluctuations.
- **Weather Conditions:** Icy roads, white-out conditions, and cold snaps present obvious threats to field operations. COPA Security's strict adherence to vehicle safety, speed limits, and the posting of warning signs assist in minimizing the potential for vehicular accidents that may result in a spill. In addition, North Slope facilities are engineered to withstand Arctic conditions.
- **Traffic Patterns:** Changes in traffic patterns may increase the risk of vehicles colliding into well lines. COPA Security's strict adherence to vehicle safety, speed limits, and the posting of warning signs or traffic cones will help to minimize the potential for vehicular accidents that may result in a spill.
- **Unplanned Shutdown Trans-Alaska Pipeline System:** If Alyeska Pipeline Service Company unexpectedly shuts down the Trans-Alaska Pipeline System, the risk to COPA operations increases. COPA's advanced communication system enables immediate communication between Alyeska Pipeline Service Company and the North Slope operators, which allows for the coordination of impacts and minimizes the risks due to a shutdown of the pipeline.

Conditions specific to Alpine operations that potentially increase the risk of discharge, and actions taken to eliminate or minimize identified risks, are summarized below:

- **Upheaval Buckling:** Buried pipelines in the Arctic are installed at temperatures that are below their operating temperatures. Because buried pipelines are restrained during thermal expansion, significant compressive force develops in pipelines that increase from their installed temperature to their operating temperature. This compressive force may cause upheaval buckling (vertical buckling displacement of a pipeline due to low lateral stability provided by the pipeline's overlying soil). The cross-country pipelines buried at the Colville River crossing are located at sufficient depth to avoid upheaval buckling.
- **High Water/Ice:** High water and/or ice during spring break-up could increase the risk of discharge from pipeline crossings over rivers. To decrease risk of a discharge, pipeline crossings over rivers are built above flood levels and are engineered to withstand ice impact and jamming. The cross-country pipeline crossing at the Colville River is a below-river crossing; thus, it is not affected by high water or ice. High water could also increase the risk of discharge in locations where a large flood (200-year event) could threaten access to drill sites or in-field oil piping. In the event a large flood causes an emergency situation, to decrease risk of a discharge, Alpine Operations may initiate an emergency de-inventory of the affected pipelines. The emergency de-inventory would stop production and injection operations, and the affected pipelines would be emptied and depressurized.
- **Permafrost Thaw Subsidence:** The weight and heat from a buried operating pipeline causes some differential thaw subsidence at locations where permafrost soils exist. Permafrost soils are not found in the underground crossing area of the cross-country pipeline route.

- **Roadless Areas:** To decrease risk of discharge, automated process control equipment can be installed at wells and pipelines to allow continuous monitoring of production factors, such as wellhead temperature and pressure, annuli pressures, choke and valve positions, gas, and/or liquid level in the well cellar.

## 2.5 DISCHARGE DETECTION [18 AAC 75.425(e)(2)(E)]

### 2.5.1 Drill Sites and Production Facilities

Routine tours of drill sites and production facilities by Operations personnel can detect leaks or spills from the drill sites.

Production wells capable of unassisted flow are equipped with surface safety valves that are monitored and controlled by an automated system; wells may also be equipped with subsurface safety valves. The system is designed to shut in well production automatically when the pressure transmitter senses pressure below a specified set point. At CD3, because it is remote, the wellheads are fully instrumented to allow continuous, remote monitoring of wellhead pressure and temperature, well annulus pressure (inner and outer annuli), and choke and valve positions. In addition, each well house at CD3 is equipped with a gas detector and liquid level detector in the well cellar that ties in to the automated system.

### 2.5.2 Alpine Oil Pipeline

The Alpine crude oil transmission pipeline (Alpine Oil Pipeline) is monitored for leaks using three different methods: 1) metered balancing, 2) computational pipeline monitoring, and 3) visual surveillance.

<u>Metered Volume Balancing</u>

Volumetric balancing is one method used to monitor for leaks along the Alpine Oil Pipeline. This method compares the volume leaving the pipeline against the total volume entering the pipeline over various time periods. Calculations are made using meter readings corrected for temperature and pressure to standard barrel conditions (0 pounds per square inch gauge [psig] and 60 degrees Fahrenheit [°F]). Volume balances of the Alpine Oil Pipeline are performed at 1-minute, 1-hour, and 24-hour intervals.

A custody transfer metering system is installed at Alpine and meters are installed at CPF-2, where the Alpine Oil Pipeline terminates. Custody transfer metering at Alpine consists of a meter skid with a meter prover. This combination provides the most accurate volume measurement currently accepted by industry. The custody metering skid uses turbine meters as the primary flow measuring element. Oil volumes are computer-corrected to industry standard reference conditions of 0 psig and 60 °F.

Meter provers are used to develop correction factors to account for changes in temperature, pressure, meter wear, etc. Meter "proofs" are obtained on a regular basis and as required by changes in operating conditions. Additional proving can be done if discrepancies in the volume balance become evident or if meter correction curves show a shift.

While the Alpine Oil Pipeline operates full (line packed), variations in the meter readings, changes in the average pressure and temperature of the crude, and different pipe diameters cause "noise" that make exact volume balancing impossible. This noise is reduced as the balance is taken over more throughput (i.e., longer time periods), but it is never entirely eliminated. Thus, in volume balancing leak detection, a maximum variation, or imbalance, is set for various lengths of time. Note that in volume balancing, the balance over several days should lose and gain, with a net variation of about zero.

A consistent loss or gain trend indicates a bias in the measurement system or possibly a small leak (consistent loss).

Computational Pipeline Monitoring

Computational pipeline monitoring involves using algorithmic tools to perform statistical analysis to determine hydraulic anomalies that may indicate a leak or spill. Real-time probability analysis is performed on the Alpine Oil Pipeline by a dedicated system using a proprietary third-party software package. Statistical analysis is performed on the pipeline flow rates and pressures to identify fluctuations such as a drop in pressure or a change in flow. This statistical approach is limited to detecting leaks that affect pipeline flow and detecting pressure that is noticeable within the normal flow and pressure fluctuations.

Advanced process automation controls monitor the compensated volumes, pressures, and temperatures entering and leaving the pipeline. This information is distributed through the SCADA system and handed off to a dedicated computer system running the software package LINEGUARD™. LINEGUARD™ performs dynamic pipeline monitoring using a material balance calculation on the system at 5-minute, 1-hour, and 24-hour intervals to detect volume imbalance and thus possible leak. LINEGUARD™ also analyzes inlet and outlet flow rate, calculated segment flow rate and measured pressures to determine leak location.

The material balance calculation determines system imbalance by subtracting the sum of the volume into and out of the pipeline from the calculated volume of fluid contained in the pipeline (known as "linepack"). LINEGUARD™ calculates pipeline linepack using measured pressure, temperature, and density data gathered by process automation controls and sent to the SCADA system, taking into account temperature fluctuations and known physical or hydraulic characteristics of the pipeline system. The calculated volume imbalance is then compared to the set leak thresholds and alarms are generated if the thresholds are reached. LINEGUARD™ also calculates flow rate in each segment of the pipeline system, and uses those values along with pressure and flow changes measured at inlets and outlets of the pipeline system to estimate the location of a leak. The system accounts for the starting/stopping of shipping pumps and can accommodate shutdown periods.

Visual Surveillance

The Alpine Oil Pipeline and Diesel Pipeline are aboveground pipelines supported by vertical support members, with the exception of the crossing at the Colville River. Weekly visual inspections (weather and equipment permitting) are made by aerial surveillance in accordance with 18 AAC 75.055(a)(3); a log is completed by surveillance personnel. For the sections of the pipelines located on the facility, daily inspections are performed as part of routine operations.

As an added measure of leak detection, aerial surveillance can be conducted using a FLIR-equipped aircraft, weather and safety conditions permitting, to survey piping for temperature anomalies that could be indicative of a leak or certain other conditions. During winter snow conditions, FLIR equipped flights are conducted as part of the weekly aerial surveillance. FLIR surveillance may be delayed due to emergency use of the FLIR in other locations, or mechanical failure or routine maintenance of the aircraft or FLIR system. Therefore, COPA relies upon weekly visual aerial surveillance to meet requirements of 18 AAC 75.055(a)(3).

If a minor leak is suspected, it is the responsibility of the Pipeline Controller or his designee to dispatch qualified personnel to visually check the line. Communications with the Pipeline Controller and facility operators is maintained so that appropriate action can be taken to mitigate a leak if discovered.

### 2.5.3 Facility Oil Piping and Flowline

Facility oil piping is visually inspected for leaks during routine operations. Well lines with emergency shutdown valves are monitored with pressure sensors located at the drill site manifold. Flowlines are monitored by pressure sensors at the drill sites and production facilities that trigger alarms and emergency shutdown when abnormally low pressures occur.

Daily operation of flowlines is monitored continuously by the SCADA system, using flow meters and pressure and temperature sensors to provide real-time information on pipeline status to control room operating personnel. In order to verify correct operation of the system, regular checks are conducted on the equipment employed, including the hardware and associated software.

Routine visual observation of the pipelines to detect leaks occurs during road travel by field and/or security personnel, or during overflights of the pipeline route when no road access is available. Additionally, employee and contract personnel drive the road system adjacent to pipeline routing to the satellite drill sites. Elevated pipelines adjacent to the road system allow for visual detection of leaks from pipeline failure, valves, or tie-in connections. Should a pipeline failure manifest itself as a small leak and spill site, undetected by leak detection systems, it would likely be observed by personnel traveling by road or aircraft.

### 2.5.4 Aboveground Oil Storage Tanks

Alpine aboveground oil storage tanks with capacity greater than 10,000 gallons are elevated and located within secondary containment areas or have double-walled construction. At a minimum, visual checks to detect leaks or spills below the tank in the containment area and/or sump occur daily at manned facilities, such as CD1, or each time an unmanned facility, such as a satellite drill site, is visited as part of scheduled operational rounds. In accordance with 18 AAC 75.075(c), inspection of secondary containment areas for ADEC-regulated aboveground oil storage tanks occurs at least once per week. Tanks equipped with level indicators and/or alarms are monitored by the control room operating personnel through the SCADA system. An alarm or other system indication of abnormal low-level is investigated.

## 2.6 WAIVERS [18 AAC 75.425(e)(2)(F)]

Waivers follow this page, as described below:

- September 13, 2007. Waiver for Flow Line Marker Requirements.
- October 7, 2004. Waiver of Cathodic Protection and Protective Wrapping/Coating Requirements for Underground Line (Tank CF-T-50090 to Module A2).

# STATE OF ALASKA

**DEPT. OF ENVIRONMENTAL CONSERVATION**
**DIVISION OF SPILL PREVENTION AND RESPONSE**
**INDUSTRY PREPAREDNESS PROGRAM**
**Exploration Production & Refineries**

*SARAH PALIN, GOVERNOR*
555 Cordova Street
Anchorage, AK 99501
PHONE: (907) 269-30
FAX: (907) 269-7687
http://www.dec.state.ak.us


September 13, 2007

File No.: 305.30
(CPAI-Alpine & Kuparuk)

Ms. Leigh McDaniel
ConocoPhillips Alaska, Inc.
P.O. Box 100360
Anchorage, AK 99510-0360

Subject: **ConocoPhillips Alaska, Inc. (CPAI) Oil Discharge Prevention and Contingency Plans for the Kuparuk River Unit and Alpine Development Participating Area. Waiver for Flow Line Marker Requirements**

Dear Ms. McDaniel:

The Alaska Department of Environmental Conservation (ADEC) has reviewed your August 20, 2007 request (revised) for a waiver from the flow line marker requirements in 18 AAC 75.047(e) for CPAI Kuparuk and Alpine facilities. The letter reflects CPAI's revised request as agreed upon in our August 9, 2007 meeting.

Under 18 AAC 75.047(e), line markers must be installed and maintained over each onshore flow line at road crossings and at one-mile intervals along the remainder of the pipe by December 30, 2007. The intent of the regulation is to facilitate rapid shutdown of a leaking line by quickly identifying the line. CPAI is planning to install line markers at all road crossings by December 30, 2007, but is seeking a waiver from the requirement for line markers at one-mile intervals along the cross-country portions of flow lines.

In accordance with 18 AAC 75.015, ADEC may waive a requirement if the owner or operator demonstrates that an equivalent level of protection will be achieved by using a technology or procedure other than that required by 18 AAC 75.005 – 18AAC 75.085.

ADEC approves the waiver request based on the following conditions that provide an equivalent level of protection:

1. CPAI will install additional line markers where flow lines approach drill pads for long spans of remote flow lines by the end of 2007.

2. CPAI pipeline mapping information currently allows rapid identification of flow lines by security, surveillance, and other personnel during routine and emergency operations. CPAI has provided us with a copy of the pipeline mapping data file.

If you have any question, please contact me at (907) 269-7640.

Sincerely,

Laurie Silfven

Laurie Silfven
Acting Section Manager

cc: Betty Schorr, ADEC
Tanya Verbyla, ADEC
Ed Meggert, ADEC, NART, Fairbanks
Todd Nichols, ADFG, Fairbanks
Jack Winters/Mac McLean, ADNR Habitat, Fairbanks
Carol Fries, ADNR, Anchorage
Carl Lautenberger, USEPA
Capt. Mark DeVries, USCG Sector-Anchorage
Johnny Aiken, North Slope Borough
Melanie Barber, USDOT
Leonard Lampe, Nuiqsut
The Honorable Carl Brower, Mayor of Nuiqsut

STATE OF ALASKA

FRANK H. MURKOWSKI, GOVERNOR

555 Cordova Street
Anchorage, AK 99501
PHONE: (907) 269-3094
FAX: (907) 269-7687
http://www.state.ak.us/dec

**DEPT. OF ENVIRONMENTAL CONSERVATION**
**DIVISION OF SPILL PREVENTION AND RESPONSE**
**INDUSTRY PREPAREDNESS PROGRAM**
**Exploration Production & Refineries**

October 7, 2004

File No: 305.35 (CPAI-Alpine)

Mr. Jason Charton/Ms. Shellie Colegrove
Alpine Development Project
ConocoPhillips Alaska, Inc.
P.O. Box 100360
Anchorage, AK 99510-0360

Dear Mr. Jason Charton/Ms. Shellie Colegrove:

**SUBJECT:** ConocoPhillips Alaska, Inc. (CPAI) Alpine Development Participating Area, Oil Discharge Prevention and Contingency Plan (plan), Plan Number 014-CP-4140. Waiver of Cathodic Protection and Protective Wrapping/Coating Requirements for Underground Line (Tank CF-T-50090 to Module A2).

The Alaska Department of Environmental Conservation (ADEC) has reviewed your request to waive the requirements of 18 AAC 75.080(b)(1)(A) for the underground line being installed between tank CF-T-50090 and module A2. In accordance with 18 AAC 75.015, ADEC may waive a requirement if the owner or operator demonstrates that an equivalent level of protection will be achieved by using a technology or procedure other than that required by 18 AAC 75.005 – 18AAC 75.090.

According to your letter dated September 12, 2004, the underground line consists of a continuous run of ½-inch diameter, 316L stainless steel tubing encased in PVC-coated insulation; the PVC will be supported by centralizers within fusion-joined, 8-inch HDPE casing. The line will be added to CPAI's below grade pipe monitoring program and will be monitored with a gas detection device annually via a leak detection standpipe. While the line will primarily be used to transfer DRA, it may also be used to transfer miscellaneous hydrocarbons.

18 AAC 75.080(b)(1)(A) requires protective wrapping or coating and cathodic protection appropriate for local soil conditions. Our review indicates that the proposed design, coupled with annual monitoring, is sufficient to satisfy the intent of this regulation. The ADEC is granting a waiver of the protective wrapping or coating and cathodic protection requirements of 18 AAC 75.080(b)(1)(A) for the underground line being installed between tank CF-T-50090 and module A2.

The waiver is subject to the following conditions:

1) CPAI must use the design construction described in your September 12, 2004 letter.

2) The line must be monitored with a gas detection device on an annual basis (or greater frequency), and be part of CPAI's below grade pipe monitoring program as described in your September 12, 2004 letter.

3) The Alpine plan must be revised at the next routine update to include this waiver approval letter.

Please be advised that the approval of this waiver does not relieve you of the responsibility for securing other state, federal or local approvals or permits, and that you are still required to comply with all other applicable laws.

If you have any questions, please contact Laurie Silfven at 269-7540 or me at 269-7680.

Sincerely,

Lydia Miner

Lydia Miner
Section Manager

cc: Bill Hutmacher, ADEC
Laurie Silfven, ADEC
Sam Saengsudham, ADEC
Stephen Geddes/Jeanie Shifflett, CPAI, Anchorage
Ed Meggert, ADEC, NART, Fairbanks
Mark Fink, ADFG, Anchorage
Al Ott/Mac Maclean, ADFG, Fairbanks
Sam Means, ADNR, Anchorage
Carl Lautenberger, USEPA
Capt. Ron Morris, USCG MSO-Anchorage
Rex Okakok, North Slope Borough
Jim Taylor, USDOT
Leonard Lampe, Native Village of Nuiqsut

# PART 3 SUPPLEMENTAL INFORMATION [18 AAC 75.425(e)(3)]

## 3.1 FACILITY DESCRIPTION AND OPERATIONAL OVERVIEW [18 AAC 75.425(e)(3)(A)]

### 3.1.1 Facility Ownership and General Site Description [18 AAC 75.425(e)(3)(A)]

The Alpine field, satellites, and pipelines are located within the North Slope Borough on federal, state, and private lands in the central Arctic Coastal Plain of Alaska's North Slope. ConocoPhillips operates the drill sites, oil processing facility, and pipelines. The ownership of Alpine is as follows:

Operator: ConocoPhillips 100%

Alpine is located in the area of the Colville River delta approximately 35 miles west of Kuparuk Central Processing Facility #2 (CPF2). Alpine facilities are located in the vicinity of major channels of the Colville River, including the Nigliq Channel, the Sakoonang Channel, and the Tammaiyagiaq Channel and within the area of the Tinmiaqsiugvik River and Fish Creek. The Alpine Pipeline system runs from Alpine's central processing facility at CD1 pad to Kuparuk CPF2. The village of Nuiqsut lies approximately 8 miles south of the main pad, CD1..

Alpine's footprint consists of one main gravel pad (CD1) with base camp, wells, production modules, oil piping, materials and chemical storage, and processing facility (ACF), with five satellite drill sites on gravel pads (CD2, CD3, CD4, CD5, and GMT1), and gravel roads to drill sites CD2, CD4, CD5 and GMT1. Alpine drill sites CD1, CD2, CD3, CD4, and CD5 are located within the Colville River Unit, while drill site GMT1 is located within the Greater Mooses Tooth Unit. Approximately 100 to 300 employees are housed at the Alpine CD1 base camp facility during normal operations. The Alpine processing facility processes sales-quality crude oil, separating oil from water and gas. The processing facility is capable of processing up to approximately 150,000 barrels of oil per day.

A crude oil transmission pipeline, a diesel pipeline, a fiber optic cable, and a utility (seawater) pipeline extend 34.2 miles cross-country and aboveground on vertical support members (VSMs) from CD1 to Kuparuk CPF2. The crude oil transmission pipeline, diesel pipeline, fiber optic cable, and seawater pipeline cross beneath the main channel of the Colville River through bored and cased holes. Other minor river and stream crossings are aboveground, on VSMs.

Drill site CD2, is located west of CD1 and consists of wells, production modules, oil piping, and materials storage. CD2 is connected to CD by a 3-mile-long gravel road. A 5,000-foot airstrip lies adjacent to this gravel road near CD1.

Drill site CD3 lies to the north of CD1 and consists of a gravel pad, wells, production modules, oil piping, chemical storage, and a 3,040-foot-long airstrip that provides year-round access by aircraft. During winter, access to CD3 may also be via ice road.

Drill site CD4 lies to the south of CD2 and consists of a gravel pad, wells, production modules, and oil piping. A 3.6-mile-long gravel road connects CD4 to the CD2 access road.

Drill site CD5 lies to the west of CD4 and consists of a gravel pad, wells, production modules, oil piping, chemical storage, and approximately 6-mile long gravel road connected to the CD4 access road.

Drill site GMT1 lies within the National Petroleum Reserve – Alaska, and consists of a gravel pad, wells, production modules, oil piping, and approximately 8-mile long gravel road connected to CD5.

Each drill site is linked to an in-field pipeline system that connects to the Alpine processing facility at CD1. The in-field pipeline system consists of three-phase flowlines (oil, water, gas), gas lines (reinjection gas and/or miscible injection), and water lines. The CD3 in-field pipeline system also includes a diesel pipeline. The flowlines are supported on VSMs and extend approximately 3 miles from CD2, 6.5 miles from CD3, 4.5 miles from CD4, approximately 6 miles from CD5 to the CD4 flowline tie-in, and approximately 8.5 miles from GMT1 to the CD5 flowline tie-in. The Nigliq Channel bridge carries the CD5 flowline over the channel.

Alpine location maps and facility diagrams are provided in Section 1.8.

**Gravel Pads**

The Alpine gravel pads are, at a minimum, 5 feet above the surrounding tundra elevations. The shoulder elevations of the pads are at least 1 foot above the 200-year flood-event elevations. As a way to mitigate excessive storm water drainage, drainage basins are built into the CD1 pad using slight gravel grading change to collect excess water. The drainage basins collect snow/ice melt and precipitation during break-up and summer, so it does not run off the pad. During this time, the drainage basins are visually checked as part of routine operations and are drained as necessary.

**Waste Disposal and Water Use**

Solid waste, oily waste, and sewage solids are incinerated at the site or transported to Kuparuk or Prudhoe Bay for disposal. Gray water is injected into a permitted Class 1 disposal well at CD1. Drilling wastes are managed either by annular disposal into permitted wells at the drill site, or by transportation and injection into an approved Class 2 disposal well at CD1. Non-combustible solid waste is transported to approved, off-site facilities for disposal.

During operations, fresh water is used at the facilities for maintenance drilling, potable water, firefighting, and dust suppression. A pump house is located at nearby lakes and is permitted to provide untreated water to CD1, where it is processed before use. The water in the lakes is accessed by pipeline from CD1. Additional lake water sources may be permitted and used during drilling operations.

### 3.1.2 Facility Oil Storage Containers [18 AAC 75.425(e)(3)(A)(i) and (ii)]

Appendix D contains the number, type, and oil storage capacity of each container regulated by ADEC covered under this plan and its installation date, design, construction, and general condition. The type and amount of oil stored in each container is also listed. Information about containers regulated under spill prevention, control, and countermeasures criteria is provided in the Alpine SPCC Plan.

### 3.1.3 Transfer Procedures [18 AAC 75.425(e)(3)(A)(vi)]

Transfer procedures are described in Section 2.1.5.

During drilling activities and production operations, a tanker truck or mobile refueling tank is used to refuel equipment. These transfer operations are conducted with the fueling truck driver in constant attendance.

All fueling-hose transfer connections have a drip pan. The fueling truck also carries absorbents, waste containers, and tools to contain and clean up minor drips and spills. If necessary, the fueling truck is chocked to prevent vehicle movement during the transfer.

### 3.1.4 General Description of Pipelines and Processing Facilities [18 AAC 75.425(e)(3)(A)(vii)]

**Pipelines**

Flowlines

Flowlines connect the drill sites to the Alpine central processing facility. The separate three-phase oil production, gas and seawater pipelines (in-field pipelines) required for CD1 to CD2 operations cross underneath the gravel road near the west end of the airstrip at CD1, then run on the north side of the road to CD2. The road provides visual surveillance capability and flood protection for the pipelines. The in-field pipelines for CD1 and CD2 include two 8-inch diameter lines (gas and seawater) and one 20-inch diameter, three-phase line. With the exception of the small road crossing, the CD1 and CD2 in-field pipelines are supported on VSMs at least 5 feet above the tundra, with 50- to 65-foot spacing for approximately 3 miles. The pipelines connecting other drill sites consist of three-phase oil production, gas lift and/or miscible injection, water lines, and a diesel pipeline between CD1 and CD3. The pipeline corridor extends approximately 6.5 miles to CD3, 4.5 miles to CD4, approximately 6 miles to CD5, and approximately 8.5 miles to GMT-1. Flowlines sizes and distances are presented in Table 2-6 and are illustrated in the Alaska Clean Seas (ACS) *Technical Manual* Map Atlas Sheets 12, 16, 17, 20, 22, 121, 125, and 126 and facility diagrams in Section 1.8.

Pipeline elevation breaks created by raised sections of the pipeline at channel crossings aid in reducing spill volume, because the elevation breaks would trap liquids in the damaged pipeline away from the rupture.

Facility Oil Piping

Facility oil piping connects the wellhead to the flowline, and also includes oil piping associated with ADEC-regulated oil storage tanks. Produced fluids flow from the wellheads through well lines to drill site manifold buildings, which connect to flowlines. Manifold buildings are considered to be an interconnection and not ADEC-regulated facility oil piping under 18 AAC 75.080 if the buildings provide weather protection, include monitors and alarms for detecting abnormal conditions, and have floors, sills or other components that would contain most oil spills originating from piping within the building. Oil piping connecting an ADEC-regulated oil storage tanks to a fuel dispensing system, fill cap or valve, or transfer pump is considered facility oil piping.

Crude Oil Transmission Pipeline

The 34.2-mile crude oil transmission pipeline is constructed of steel, covered with insulation, and has a nominal diameter of 14 inches. The pipeline is designed to U.S. DOT standards for crude oil pipelines. The pipeline is cased within a carrier pipe where it crosses underneath the Colville River. Both the carrier pipe and the casing are fusion bonded epoxy coated and the annulus is equipped with leak detection.

The insulated pipeline transports hot crude oil with a maximum design temperature of 180 degrees Fahrenheit (°F). The pipeline is elevated on VSMs. A minimum height of 5 feet is maintained for the entire length of the crude oil transmission pipeline. To further enhance caribou and human crossings, selected portions of the elevated pipeline exceed the 5-foot minimum (7 to 8 feet average) near streams and lake complexes where caribou and human use is high.

The crude oil transmission pipeline crosses three rivers, two of which are aboveground crossings, and the Colville River crossing, which is the only underground portion of the pipeline. River bank setbacks of approximately 300 feet were established for bored-hole entry and exit locations at the Colville River crossing. Horizontal directional drilling (HDD) was used to bore the crossing underneath the Colville River. These setbacks enhance caribou and human use crossings and achieve channel-migration setback allowances. The pipeline at this location is externally coated, while the aboveground portion is uncoated steel pipe, insulated with polyurethane and protected with a metal jacket.

The pipeline support system has several components including VSMs, cross members, connectors, and pipe saddles. VSMs spaced approximately 55 to 70 feet apart, safely support the pipeline. Approximately 2,760 VSMs were placed in the transportation corridor. The VSMs are embedded at depths between 20 to 25 feet.

Table 3-1 contains the design basis for the crude oil transmission pipeline. The table also includes the seawater and diesel pipelines that parallel the crude oil transmission pipeline.

**TABLE 3-1: CROSS-COUNTRY PIPELINE DESIGN BASIS**

| LINE | OUTSIDE DIAMETER (IN) | DESIGN TEMP (°F) | CORROSION ALLOW | MAXIMUM ALLOWABLE OPERATING PRESSURE (PSI) |
|---|---|---|---|---|
| Crude Oil Line | 14 | -50/180 | 0 | 2,064 |
| Seawater Line | 12.75 | -50/150 | 0 | 2,160 |
| Products Line | 2.375 | -50/100 | 0 | 1,366 |

Vertical loops were placed in the pipeline in lieu of valve hardware, except at the pipeline inlet and outlet where automatic ball valves are located. This alternative was developed in recognition of the relatively low terrain relief of the North Slope and the spill risks associated with valves. These loops were installed to form a terrace structure that significantly limits the amount of oil that could be spilled due to drain-down effects. The potential pipeline spill volumes with this design are less than those associated with the valved pipeline alternative. Vertical loops perform the same function as valves without the hydraulic inefficiencies and maintenance concerns associated with check valves. The loops meet the requirements of Title 49 of the Code of Federal Regulations (CFR), Part 195. Besides reducing the risk and size of spills, the loops do not require maintenance and testing, as do valves, therefore reducing the need for gravel heliports on the tundra and for tundra access. The pipeline contains seven vertical loops, one on each side of the Colville, Miluveach, and Kachemach rivers, and one approximately 1.5 miles east of the Colville River.

**TABLE 3-2: ALPINE CROSS-COUNTRY PIPELINE VERTICAL LOOP PLACEMENT**

| LOCATION DESCRIPTION | PIPELINE DISTANCE FROM ALPINE PROCESSING FACILITY (FT) | PIPELINE ELEVATION (FT) |
|---|---|---|
| Alpine Processing Facility Pig Launcher | 0 | 32 |
| Vertical Loop HDD West | 47,886 | 34 |
| Vertical Loop HDD East | 53,190 | 35 |
| Vertical Loop #1 | 62,141 | 68.25 |
| Vertical Loop #2 | 104,554 | 71.66 |
| Vertical Loop #3 | 105,809 | 99.61 |
| Vertical Loop #4 | 124,618 | 101.1 |
| Vertical Loop #5 | 127,935 | 114.26 |
| CPF-2 Pig Receiver | 182,676 | 88.58 |

### Processing Facilities

The oil processing facility is designed as a feed-forward operation. The production components are progressively separated by flowing through the inlet separator, the low pressure separator, and the dehydrator prior to the sales quality oil entering the Alpine crude oil transmission pipeline via the crude-oil shipping pumps.

Most of the natural gas liquid knocked out of the gas in the compressor aerial coolers is re-injected. Some natural gas liquids are passed back into the inlet separator. Produced gas, along with formation fluids and solids, are removed from the liquid stream in this vessel.

Control Strategy

The oil separation operation receives crude oil from the CD1 and satellite drill sites. Through heating and gravity segregation, the gas is separated from the liquids. Gas is sent to the gas compression unit for compression to re-injection pressures. Oil is separated from water by settling and electrical coalescing. Gas condensate, which drops out of the gas in the compression stages, is blended with sales crude or with the gas for use in the MI system.

The primary objective of this process operation is to reduce the maximum water content of the oil to less than 0.35 percent by volume to meet final product specifications.

Water content of the oil prior to metering is measured, and alarms note when the results are outside specified ranges. There is no automatic control of water content. Water content is affected by the Alpine processing facility oil throughput, the fluids temperature in the production vessels, the effectiveness of the low pressure separator, and the effectiveness of the dehydrator. Recycling of off-specification oil to the off-spec/slop tank and/or the inlet separator is an operator-initiated action. Due to the off-spec tank's small size, production diversion to the slop oil tank for special treatment is limited.

### Inlet Crude Oil

Produced fluids from satellite drill sites are transferred via pipeline to the Alpine processing facility and mixed with the fluids from CD1. CD1 production wells are located adjacent to the Alpine processing facility, and the CD1 well-test separator is located in the Alpine processing facility. The test/start-up separator is also used as the source of start-up fuel gas for the plant and for diversion of injection water/auxiliary fuel

gas from Kuparuk. Except during the diversion of start-up fuel gas and injection water/auxiliary fuel gas, the test/start-up separator fluids are added back into the CD1 and satellite drill site production fluid stream. The combined drill site fluid streams enter the Alpine processing facility at 90°F to 110°F. Flow into the Alpine processing facility is controlled by the choke valves for each producing well.

**Outlet Oil**

The crude cooler pre-heats the incoming production by cross-exchanging heat and subsequently cooling the sales crude oil to a range of 145°F to 150°F before going through a series of trim coolers for additional sales crude oil cooling to 115°F to 125°F depending on the time of year. In order to avoid permafrost damage at the river crossings, the maximum Alpine processing facility outlet temperature is 180°F. The crude contains 2.8 percent wax by weight (116°F wax melt-point and +5°F crude pour-point).

There are also minimum flow and temperature requirements for the crude oil transmission pipeline to avoid coagulation of the oil at low ambient temperatures. Falling oil temperature in the winter could result in highly viscous oil, increasing the flowing pressure drop in the pipeline and restricting throughput. Winter crude oil temperatures must exceed 116°F in order to minimize pigging, while summer temperatures are limited to the maximum specified temperature of 142°F.

A pressure control valve maintains the crude oil transmission pipeline inlet pressure at or below 2,065 pounds per square inch gauge (psig). The oil deliveries to Kuparuk CPF-2 normally encounter a delivery pressure minimum of 1,400 psig. The pipeline system is limited by the 2,100-psig pressure limit of the pipeline between Alpine and Kuparuk. Normal plant outlet oil pressure is 1,870 psig. The maximum sulfur/hydrogen sulfide content of the export oil is 50 parts per million by weight.

The minimum allowable flow rate conditions during -50°F weather for the line to Kuparuk are as follows:

- Flow rate, 25,300 barrels per day
- Pipeline Inlet Pressure, 1,480 psig
- Pipeline Outlet Pressure, 1,435 psig
- Pipeline Inlet Temperature, 180°F
- Pipeline Outlet Temperature, 100°F

<u>Water/Gas Re-injection and Produced Water</u>

Imported seawater and formation produced water is alternately injected with gas into the formation to enhance oil recovery. This process is referred to as miscible water-alternating-gas injection. Seawater comes from CPF-2 through the cross-country seawater (utility) pipeline. The maximum design-water injection rate is 150,000 barrels of water per day. The maximum wellhead injection pressure is 2,700 psig.

The processing facilities have been designed to handle and dispose of up to 10,000 barrels of water per day of formation produced water via the CD1 Class 1 disposal well. The design disposal well temperature and pressure are 214°F and 2,700 psig, respectively.

Produced gas is dehydrated using a triethylene glycol system to prevent hydrate formation in the surface piping and downhole. The design-plant outlet-gas injection pressure is 5,500 psig, with a maximum wellhead injection pressure of 4,200 psig. The design-plant outlet-gas injection temperature is 205°F, with

maximum wellhead injection temperature of 180°F. The facility is designed with an injection/lift gas design rate of 180 million standard cubic feet per day.

### Electrical Power

During drilling operations, the drilling rig may provide its own power using generators fired on diesel. The drilling rig may also receive power directly from the Alpine processing facility. The Alpine processing facility generates electricity from fuel gas, using a primary generator with approximately 25 megawatts. This primary generator provides the base-load power requirements. Should anything happen to the primary generator, a 10-megawatt back-up gas fueled generator is available at the facility.

Two twin 5.5 megawatt gas and diesel fired turbine generators provide emergency power at CD1. These twin solar turbine power plants can also provide primary power and are often run in combination with the larger primary units. Uninterruptible power supply systems provide power to the control systems and switchgear.

Electrical power for satellite drill sites is supplied by CD1 via insulated power cables or is generated on-site by generator. Power cables to satellite drill sites are either suspended under or along VSM-supported pipelines or buried in gravel roads. Emergency power generators also may be maintained at satellite drill sites.

### Lighting of Facilities

The lighting for Alpine facilities is designed to direct light to the local area. Lighting is required for safe operations and security while minimizing misdirected lighting glare to the surrounding landscape.

### Instrumentation and Controls

The facilities in the Alpine Development Area require a control system for:

- Process monitoring and control,
- ESD functions,
- Pipeline leak detection,
- Compressor surge control,
- Fire and gas detection, and
- Vibration monitoring.

The control system is:

- A reliable, standard industrially-proven system;
- Capable of future expansion; and
- Reduces Operation's manpower requirements.

Control loops in the facility are electronic. The basic process control and safety is an integrated system used to perform process analog control and monitoring, alarming, and discreet logic function, such as normal operational equipment shutdowns/starts and stops. It is composed of easily expandable hardware and software to meet future COPA needs. It exhibits industry-proven reliability.

### Remote Electrical-Instrument Module

To facilitate the modularized/skid-mounted process equipment approach, input/output modules, terminations, and electrical equipment are mounted on each skid in a modular building called a remote electrical-instrument module (REIM). Devices on the skid associated with the electrical and control systems are wired in the fabricator's shop to the REIM electrical/module input/output. A data communication highway cable runs between the REIMs and the control room. Control system interconnects and site checkout requirements are reduced. The REIM modules require controlled environmental conditions (heating/cooling), depending on their location in the plant. Processors for control of the input/output modules are redundant and are located in the control room/auxiliary room or remotely with the input/output, depending on security of control and economic considerations.

REIM modules are associated with the larger skids and vendor packages. Where smaller modules are involved, the wiring for these is field-run on site to the closest applicable REIM unit.

### Emergency Shutdowns

A stand-alone plant ESD safeguard system, hereafter termed the safety instrument system (SIS), is used for gas ESD functions affecting personnel or plant safety. This system uses redundant "hot standby" processors and remote input/output modules in the REIMs. Shutdown signals to the SIS are from analog transmitters wherever possible, with the exception that packaged equipment uses the vendor's standard (switches or transmitters) when necessary.

The SIS is integrated with the plant control system, not just interfaced to it. This means that the SIS controller is a node or drop on the system highway and able to communicate directly with other nodes performing basic process control functions and with the operator interface terminals. Advantages of this system are that communication between devices is not dependent on an intermediate device, less programming is required, and the system is therefore more secure and reliable.

Dedicated shutdown buttons are provided in the control room console and hardwired directly to the SIS controllers for each of the levels of shutdown, except the CD1 and CD2 SIS. CD1 and CD2 control room ESD buttons are wired to the oil SIS. Communication to the CD1 and CD2 control processors occurs via the redundant M-NET communication highway and redundant communication processor racks at CD1 and CD2. A watchdog logic circuit monitors the communication module health and causes a CD1 or CD2 ESD to occur if both modules fail.

Dedicated shutdown buttons are also provided inside and outside doorways for each of the applicable process modules and REIM buildings. Remote/local ESDs, blowdown emergency shutdowns, and facility shutdowns are all considered part of the SIS.

### Operation Requirements

The main central facility is staffed by operating personnel on a 24-hour basis, with the minimum staff complement as follows:

- 1 control room operator (day and night),
- 1 to 4 central facility/drill pad operators (day and night),
- 1 shift supervisor (days),
- 1 electrical/instrument technician (days),

- 1 millwright (days), and
- 1 mechanic (days).

Satellite drill sites may not be staffed by operating personnel on a 24-hour basis; however, these sites are visited regularly, during routine operational rounds. Unmanned sites are visually inspected at least once per month. Satellite drill sites are equipped with automated remote well monitoring systems that are managed in the Operator Control Room (see Section 2.5.1).

#### Control System Architecture

The control system architecture is:

- **Distributed**: Operator interfaces in one building, and process controllers/input-output modules are distributed throughout the plant. This reduces field wiring by permitting shorter runs from module devices to input/output devices located on the ends of skids. Only data highway runs are required to control the building, enabling more work to be completed at module shops, including partial testing of system components.
- **Multi-drop Signals**: Operator interface/process controllers are in the same or adjacent rooms, and input/output modules are either centralized or distributed, but quantities are significantly reduced due to use of serially-connected field devices. Multi-drop signals are used for monitoring functions only, as a break in the wire of any device in the loop will make the information from all devices unavailable. The advantage of this system approach is the significant reduction of field wiring. Use is limited to drill site manifold buildings and selected central facility loops.

#### Facility Human Machine Interface

The facility utilizes a Supervisory Control and Data Acquisition (SCADA) software system as the basis for the human machine interface. The process control system, ESD safety system, fire system, and various equipment packages and their control systems interface with the SCADA servers. The operator interface terminals also derive their data from the SCADA servers.

The SCADA system communicates with most devices using an Ethernet highway with TCP/IP protocol and provides operator information to the REIM displays and to Kuparuk over the fiber-optic highway. Production reports, alarming, and business administration data are derived from the SCADA system.

#### Operator Station Interfaces

Operator station interfaces, also called operator interface terminals, are provided in the Alpine processing facility control room, in Modules C3, A3 REIMS, E3, and at CD1 and CD2. Operator-initiated control changes for the entire facility are performed in the Alpine processing facility control room. The operator interface terminal displays at the REIMs and drill sites are provided for the convenience of maintenance and operations staff for monitoring functions only, due to the geographical distances from the Alpine processing facility. The operator interface terminal systems are workstation computer architecture with color graphics, rather than console-style, and are equipped with printers for alarm logs, reports, etc. in the Alpine processing facility.

#### Pipeline Leak Detection

Pipeline leak detection is discussed in Sections 2.1.7, 2.1.8, 2.5.2 and 2.5.3.

## 3.2 RECEIVING ENVIRONMENT [18 AAC 75.425(e)(3)(B)]

The receiving environment for Alpine consists of the area surrounding the man-made gravel pads and roads and pipelines situated in the Colville River delta and Tinmiaqsiugvik River and Fish Creek drainage area. Large spills occurring at Alpine, particularly well blowouts and pipeline ruptures, are unlikely but have the potential of reaching tundra, open water, and/or ice.

### Nuiqsut

The Native village of Nuiqsut is located near the main channel of the Colville River, approximately 8 miles south of the Alpine Development Area. The population measured in the 2009 consensus was 379 residents. Nuiqsut provides modern amenities such as governance, infrastructure, schools, and an airport. The proximity of Nuiqsut would require close monitoring of meteorological conditions and communication and consultation with Nuiqsut representatives concerning how best to mitigate potential health effects on the community. In addition, subsistence hunting and gathering is viewed as an essential part of the culture and community and requires protection of the natural environment and its subsistence resources.

### Vegetation

The vegetation of the Alpine area reflects the severe climatic conditions of the Arctic Coastal Plain and the dynamic stream channel configurations of the Alpine area. On the delta, abandoned and active stream channels have exposed extensive mud flats. Along the coast, mud flats, sand beaches, and slumping peat bluffs add to the diversity of landforms. Inland, a more usual contingent of landforms is found, including flooded tundra, high- and low-centered polygons, and deep and shallow open lakes. Although the dominant species of vegetation in the area are associated with water-saturated soils, plants characteristic of dry areas are also present.

### Wetlands

The main portion of the Colville River Unit includes the Colville River delta, Harrison Bay, and its surrounding brackish and freshwater wetlands. The area within the Greater Mooses Tooth Unit includes drainage areas of the Tinmiaqsiugvik River and Fish Creek, and thaw lakes, marshes, and polygon-patterned ground. These wetlands are composed of a variety of habitat types that support a diverse bird community during the summer. Shore birds and waterfowl typically are most abundant. Several mammals also inhabit the area, with caribou and arctic fox most prevalent.

### Soils and Landforms

The soils of the coastal lowlands are generally marine, glacial, or alluvial. A layer of unconsolidated silt, sand, and gravel, as much as 200 feet thick, covers the Arctic Coastal Plain, the largest coastal lowland deposit in Alaska. Permafrost is continuous throughout the plain and usually extends through the layer of unconsolidated sediments into bedrock. Unfrozen areas exist at perennial springs and beneath major streams. The Colville River has a thawed area beneath its bed several hundred feet thick that may perforate the permafrost in places. This does not occur at shallower, braided streams. Poor drainage due to shallow permafrost and fine, low-permeability soils contribute to numerous thaw lakes typical of this area.

The Alpine area is characterized by low relief with mud flats, sand dunes, and ice-rich tundra bluffs along the coastline. From sea level, the land slopes upward to a maximum elevation of 30 feet near the runway at CD1. Microrelief in the area is provided by polygon rims, pingos, frost boils, and sand dunes.

## Hydrology

The hydrologic environment is characterized by large flows of water during the snowmelt runoff period, reduced flows during the summer, and little or no flow in the winter. Groundwater resources are limited by the existence of permafrost. Annual precipitation is light, averaging less than 7 inches per year, much of this falling during the summer and fall. Despite the prevalence of streams, lakes, and wetlands, the area is characterized as semi-arid due to its low annual precipitation.

Ponds and lakes are the most prevalent water bodies on the Colville River delta. Most of the ponds are located within low-centered ice-wedge polygons. Many of the ponds and lakes are shallow and freeze to the bottom in the winter. They are formed from thawing of ice-rich sediments during a “thaw-lake cycle” that includes thawing, expansion, drainage, ice aggradations, and eventual thawing again. Lakes of over 10 acres are numerous, covering 16 percent of the delta surface. These lakes are generally 11 to 15 feet deep but can be as deep as 28 feet. Because they have greater masses of ice and water to warm and melt at break-up, these lakes remain ice-covered into early July, much later than the smaller lakes.

The Colville River is the largest freshwater surface resource in the development area, with a length of 370 miles and a drainage area of 20,920 square miles. Peak runoff and corresponding peak sediment load occur from late May through early July and are attributed to snowmelt and rainfall. A second peak, due primarily to rainfall, normally occurs in July or August. Summer flows are sustained by gradual snowmelt in the mountains. Winter flows decrease to very low values (0-1,000 cubic feet per second [cfs]).

The Colville River enters the delta north of the mouth of the Itkillik River, approximately 4 miles southeast of Nuiqsut. The delta is more than 25 miles long and covers about 250 square miles. Most of the water reaching the delta is carried to the ocean through two main channels: the East Channel and the Nigliq Channel. Approximately 80 percent of the discharge at the head of the delta flows in the East Channel and its distributaries, while the remaining 20 percent flows in the Nigliq Channel. Several distributaries branch from the East Channel, including the Sakoonang and Tamayayak channels. In general, the channels of the Colville River and its distributaries are broad and relatively shallow.

Spring break-up on the Colville River generally occurs before the break-up of coastal plain streams, such as the Kachemach and Miluveach rivers. The median date of peak break-up discharge is June 2 and the peak break-up discharge at the head of the delta averages 264,000 cfs (Ray and Aldrich, 1996). Typical summer flows at the head of the Colville River delta range between 20,000 and 80,000 cfs.

The Kachemach and Miluveach rivers, which drain the Arctic Coastal Plain east of the lower Colville River, are completely underlain by permafrost. The Kachemach River is approximately 35 miles long with a drainage area of 213 square miles. The Miluveach River is approximately 40 miles long and has a drainage area of 184 square miles. Both rivers flow into the East Channel of the Colville River.

The Fish Creek drainage area consists of lakes and three significant tributary basins: Inigok Creek, Judy Creek, and Tinmiaqsiugvik (Ublutuoch) River. During flood stage in the lower Fish Creek area, one main (east) channel and a minor (west) channel are main pathways to Harrison Bay. Streams in the Fish Creek area have relatively low gradients and highly sinuous channels, though portions of the Tinmiaqsiugvik River are entrenched, which creates a narrower floodplain and steeper banks (BLM, 2004). Spring break-up occurs in the Tinmiaqsiugvik River earlier than Fish or Judy Creeks. Measurements taken near the bridge and pipeline crossing show break-up occurs during the first week in June, with peak stages noted between June 5 and 8 (BLM, 2004). Flooding and high-water conveyance along the Tinmiaqsiugvik River at break-

up occurs within the lower west floodplain during periods of high flow and/or when ice occurs in the main channel; the east and upper west floodplains are also inundated but convey little flow (BLM, 2004).

### Nigliq Channel

The topography of the land immediately west of the Nigliq Channel, just outside the Colville River delta, slopes toward the channel. The gravel access road to CD-5 could be used for spill response access and staging, and containment and control points could be established at road-stream crossings. ACS *Technical Manual,* Volume 1, Tactics C-2 and C-3 describe culvert blocking techniques that could be employed to prevent oil from reaching the other side of the gravel road if a spill occurs from in-field piping. Additionally, boom is seasonally pre-staged at the Nigliq Channel as a preventative measure.

### Oceanography

The general surface circulation of the Beaufort Sea is dominated by a clockwise gyre that produces offshore currents from the west. The average set is 1 to 2 nautical miles per day. In early 1960, Ice Island T-3 drifted at an average rate of 3 nautical miles per day in the southern Beaufort Sea. These prevailing currents move both water and ice shoreward throughout most of the year. In contrast, nearshore surface currents are variable and influenced by local winds. They might set in either an easterly or westerly direction, and are generally weak and unpredictable.

Seasonal freezing and melting and the freshwater input from large rivers are the major influences on the surface water characteristics of the Beaufort Sea. Salinity varies both geographically and seasonally, ranging from 29 to 36 parts per thousand. Temperature of seawater ranges from -1 degrees Celsius (°C) to -2.8°C under ice in winter, to just above freezing in summer.

Tides are small, about 1 foot in extreme. Associated tidal currents also are weak. All tidal phenomena are altered by ice coverage, especially shore-fast ice, with the time of the tide reduced and the range decreased. Nevertheless, Beaufort Sea tides have been known to form cracks in the shore-fast ice in mid- to late winter and to free seasonal shoreline ice.

Surface waves on the Beaufort Sea are restricted to summer periods when open water exists. During these periods, swells of 6 to 7 feet have been observed along the coast when the ice pack was far out to sea. Large waves are uncommon, probably because of the restricted area of fetch when open water exists.

Ice is present in the Beaufort Sea at least 9 or 10 months of the year and is an important factor in determining the dynamic events associated with the shoreline and coastal waters. Embayments, lagoons, and shore fringes are normally covered with fast ice during the long winter, as is the shoreline. As freezing begins in the fall, new ice forms along the coast and slowly builds seaward, often freezing to the bottom. This land-fast seasonal ice typically extends to the 5- to 10-fathom depth contour and can reach a thickness of 6 feet.

Farther out to sea lays the pack ice, consisting predominantly of multiyear flows from 6 to 12 feet thick. In summer, the pack ice is surrounded by open water and in winter, by first-year ice. Pack ice is constantly in motion, moving generally under the influence of the Arctic gyre. Ice islands such as T-3 are infrequently found within the pack ice. These islands originate from the Ellesmere Ice Shelf and can be quite large. During freeze-up, a shear zone of ice often produces open-water leads that freeze and form new seasonal ice, which in turn can be deformed under pressure. Pressure ridges and ice hummocks are often created in this shear zone.

In summer, the land-fast ice melts and the pack ice retreats northward, leaving open water along the coast. However, during periods of northerly winds, the polar pack can be blown against the shoreline east of Point Barrow. The extent of ice cover varies greatly from year to year, with its distribution a function of meteorological conditions, currents, tides, and the topography of the sea floor.

The coastal zone of the operating area includes Harrison Bay and the growing delta of the Colville River. Offshore lies Thetis Island and numerous islands associated with the river delta. The shallow depth of Harrison Bay protects it from the dynamic ice activity that occasionally occurs along the coastline.

Coastal erosion is insignificant during the winter when the seas are frozen. However, during the summer, mechanical erosion of thawed beaches and thermal erosion of coastal banks causes the shoreline to recede inland at rates of as much as 30 feet per year. Also, severe storms with significant waves can bring about changes in local topography through erosion and deposition. Sediments enter the coastal waters of the Beaufort Sea, as a result of river flow during the summer and from the coastal erosion processes discussed earlier. This results in coastal-shelf bottom materials high in silts and sands and with lesser amounts of gravel.

## Ecology

The Alpine area contains a diverse array of habitats used by wildlife for feeding, breeding, and shelter. The habitats also provide other important ecological functions. Wetlands are particularly important because of their influence on surface and ground water hydrology, water quality, bird nesting and feeding, and fish production. Estuarine wetlands produce nutrients that are exported to marine and river systems where they provide for a wide variety of plants and animals. River channels serve as transportation corridors for hunting, fishing, and recreation. The habitat types in the project area constitute a complex mosaic of biological communities that support a rich diversity of plant and animal resources.

The vegetation at the Alpine area reflects the climatic and topographic features of the area. Many shallow ponds have formed in the low-lying areas, while peat ridges and polygonal features related to frost action and ice wedges provide slightly higher, better-drained soils. Few woody plants are present, but those that do are found on drier sites where the microrelief raises them above the standing-water table. The most abundant and widespread habitat classes in the project area are wet and moist tundra. The most prominent habitat types in these classes are Wet Sedge-Willow Meadow on the delta and Moist Sedge-Shrub Meadow and Moist Tussock Tundra in the transportation corridor. Other prominent habitat classes on the delta include estuarine, river/stream, barrens, and lake/pond.

The Colville River delta is regionally important to birds and mammals. The Colville River delta is the largest and most complex river delta on the Arctic Coastal Plain of Alaska. It provides high-quality breeding habitats for water birds such as the spectacled eider, brant, tundra swan, and yellow-billed loon, as well as other water birds, shorebirds, songbirds, and predatory birds. The delta supports 29 species of water birds including 16 species that breed there. The Colville River delta provides some of the earliest open-water and snow-free areas for migrating birds during spring. The extensive salt marshes and mudflats on the delta are used by geese and shorebirds as staging areas during fall migration and by many other birds during spring and summer. Few species inhabit the area year-round.

The U.S. Fish and Wildlife Service (USFWS) has listed the spectacled eider as a threatened species throughout its range since 1993. Biologists have reported nests and broods in several areas on the Colville River delta. Most nests lie outside of areas that might be affected by spills. Guidelines for activities within the breeding range of spectacled eiders are as follows:

- Assess whether spectacled eiders are likely to use the project area for nesting or brood-rearing. Contact the USFWS for assistance. For projects conducted during the breeding season, a USFWS-approved survey for spectacled eiders should be conducted in the year of construction, prior to initiation of activities.
- If spectacled eider nests are in the project area, the following activities may require special permits within 200 meters of nest sites:
  - Vehicle and foot traffic, except on existing roads.
  - Construction of permanent facilities, placement of fill, or alteration of habitat.
  - Introduction of high noise levels, including but not limited to noise from airports, blasting, and compressor stations.
- Eiders are present on breeding grounds from mid-May through mid-September, but activities at any time of year may affect them through habitat modification.

The delta is also used seasonally by caribou for foraging and insect relief habitat and by foxes and polar bears for denning habitat. Many of these wildlife resources are hunted by local residents as an essential element of their subsistence lifestyle.

The marine waters of the Beaufort Sea, off the Colville River delta, provide habitat for bowhead and beluga whales; ringed, spotted, hooded, and bearded seals; and walruses. The beluga whale is the most abundant in northern Alaska and is an important subsistence resource for coastal residents. The ringed seal is a year-round resident and is the most abundant seal species in the Beaufort Sea.

The fish resource is composed of three major groups of fish; marine, anadromous, and freshwater. Freshwater species such as arctic grayling, burbot, and nine-spine stickleback typically reside within the confines of fresh or slightly brackish water and are generally restricted to the rivers and small streams that flow into the Beaufort Sea.

Anadromous species (arctic char, chum salmon, least cisco, arctic cisco, broad whitefish, and humpback whitefish) over-winter and spawn in the fresh water of larger rivers such as the Sagavanirktok and Colville rivers (Morrow, 1980), but tend to spend the summer in nearshore marine waters, often undergoing extensive coastal migrations. Pink salmon that spawn in the Colville River are also present in the nearshore coastal waters during the juvenile out-migration and adult return migration. Spawning of pink and chum salmon occurs in very low numbers in the Colville River and associated tributaries. The National Marine Fisheries Act recognizes waters cataloged under AS 16.05.870 (Waters Important for the Spawning, Rearing, or Migration of Anadromous Fishes) as Essential Fish Habitat. Fish Creek, Judy Creek, the Tinmiaqsiugvik River, and the Colville River are considered Essential Fish Habitat for chum and pink salmon (BLM, 2004).

Marine species such as arctic cod, four-horn sculpin, and snailfish complete their entire life cycle within the marine and coastal waters of the Beaufort Sea. Occasionally, a euryhaline species (tolerant of wide salinity ranges), such as four-horn sculpin, might intrude a few miles up into a stream or river discharging into the Beaufort Sea, but all key stages within the life cycle (such as spawning, nursery, and over-wintering functions) occur within the marine and nearshore brackish water environments.

### 3.2.1 Potential Routes of Discharge Travel to Open Water [18 AAC 75.425(e)(3)(B)(i)]

The ACS *Technical Manual* Map Atlas Sheets 1 through 29, 53, and 112 through 137 contain potential containment sites and features including sensitive receiving environments and information on potential routes of discharge.

The Alpine area encompasses portions of the Colville River delta, Fish Creek basin (including Tinmiaqsiugvik River), and surrounding terrestrial environments. The marine environment adjacent to the delta could also be affected by spills from the development. The Colville is the largest river in the United States' portion of the North Slope. This river has a major influence on local marine and terrestrial environments. At the mouth, the river forms a delta containing two major channels and several minor distributaries.

A spill on an Alpine facility pad will remain on the pad, unless the spill is near the pad edge or exceeds the retention capacity of the pad. Fuel transfers are not allowed near pad edges in order to mitigate this risk.

A spill from the cross-country transportation pipelines or the in-field flowlines will reach the tundra environment and has the potential to reach fresh-water environments. A spill from the cross-country transportation pipelines will not reach the Colville River, because of the vertical loops and the HDD-buried crossing. A spill from the cross-country transportation pipelines could reach other bodies of freshwater including the Kachemach River and the Miluveach River. A spill from in-field flowlines has the potential to reach open waters of nearby freshwater lakes, river channels, and the open marine waters of Harrison Bay. A spill from in-field flowlines over the Nigliq Channel would reach the channel and has the potential to reach Harrison Bay if not swiftly contained. However, a spill from the in-field flowlines is not likely to reach the main channel of the Colville River. A spill from in-field flowlines over the Tinmiaqsiugvik River may reach channels of Fish Creek, particularly during periods of flooding. The relatively low flow and highly sinuous nature of streams in the Fish Creek basin may preclude a spill into the Tinmiaqsiugvik River from reaching Harrison Bay.

In the unlikely event of an oil well blowout at Alpine, there is the potential for oil to reach open waters of nearby freshwater lakes, channels, and the marine waters of Harrison Bay. An oil well blowout is not likely to directly reach the Colville River; however, there is the potential for oil from the Sakoonang and Tamayayak channels to flow into the main channel of the Colville River. An oil well blowout from drill sites located outside the Colville River delta would impact nearby lakes and streams; however, it is unlikely the oil would fallout directly onto Fish Creek, the Tinmiaqsiugvik River, or Crea Creek due to the distance from existing drill sites.

Estimated volumes of oil that could reach open water are discussed below and are based on ACS *Technical Manual* Tactics T-6 and T-7.

### 3.2.2 Estimate of Response Planning Standard Volume to Reach Open Water [18 AAC 75.425(e)(3)(B)(ii)]

The following are descriptions of the worst-case discharge events that have the potential to occur at Alpine. These estimated percentages are based on the applicable response planning standard (RPS) volume calculations in Part 5.

### Storage Tank Rupture

The receiving environment for a storage tank rupture is a gravel pad, lined secondary containment basin, tundra, and possibly the shoreline of the Sakoonang Channel. The adjusted RPS volume for the oil storage tank at CD1 is 1,320 barrels. No oil reaches open water initially; however, a conservative estimate of 5 percent (66 barrels) of the volume spilled may spread to the shoreline of the Sakoonang Channel and enter its waters.

### Well Blowout in Summer

The receiving environment for a well blowout in summer is open water, gravel pad, and tundra. The RPS volume for a blowout over 15 days is 150,000 barrels, of which, approximately 4,300 barrels reaches open water of nearby lakes and small streams.

### Well Blowout in Winter

The receiving environment for a well blowout in winter is frozen lake and stream surfaces and snow-covered, frozen tundra. The adjusted RPS volume for a blowout over 15 days is 150,000 barrels. No oil enters open water.

### Crude Oil Transmission Pipeline Spill to Miluveach River in Summer

The receiving environment for a crude oil transmission pipeline spill in summer is the Miluveach River. The adjusted RPS volume for a spill from the Alpine crude oil transmission line is 2,830 barrels, all of which enters open water.

## 3.3 COMMAND SYSTEM [18 AAC 75.425(e)(3)(C)]

Oil spill response will use an ICS that is compatible with the ARRT *Alaska Federal/State Preparedness Plan for Response to Oil and Hazardous Substance Discharges / Releases (Unified Plan)*. The ICS organizational structure is based on the National Incident Management System and provides clear definition of roles and lines of command, together with the flexibility for expansion or contraction of the organization.

The basic ICS organizational structure is shown in Figure 3-1. This structure is designed to expand according to the needs of the incident. For Tier I incidents, the SRT will fill the basic ICS positions. For Tier II/III incidents, an expanded ICS structure would be staffed by the COPA Incident Management Team (IMT). The COPA IMT is comprised of North Slope and Anchorage staff employees and contractors. COPA IMT staffing changes periodically, as the workforce changes; the COPA *Alaska Response Teams Carry-All* maintains the most up-to-date listing of IMT (including QI) member name, location, telephone number, and functional role within the ICS. A comprehensive description of the COPA IMT structure and roles and responsibilities associated with various positions is provided in the *ConocoPhillips Incident Management Handbook* (IMH). Copies of the Carry-All and IMH are made available to COPA IMT members in electronic form on the COPA intranet and in paper form at all COPA Emergency Operations Center locations.

In most Tier I incidents, the SRT can effectively control the incident. The Drilling Supervisor fulfills the role of initial On-Scene Commander. Additional resources are activated under the ICS, as needed, to fill support roles.

Tier II/III spill response is initiated by the On-Scene Commander and the. Alpine IMT is activated. The Alpine IMT will take initial Command, working from the Alpine Emergency Operations Center located at Alpine CD1 Pad. If the response exceeds capabilities of the Alpine IMT, Command of the response may transition to the Kuparuk IMT who will operate from the Kuparuk Emergency Operations Center located at Kuparuk Operations Center. Once the response level is ascertained, the appropriate IMT begins to provide support to the field responders and to coordinate the collection and distribution of information. Additional support, such as in technical areas regarding source control and environmental, may be provided by the Anchorage IMT who will operate from the Anchorage Emergency Operations Center located in COPA Anchorage Office Complex.

ACS will be activated to stand by for spills until an assessment is performed. Once the assessment is complete, ACS is either released or mobilized. ACS provides additional manpower and equipment resources from Deadhorse to assist in spill containment and recovery. North Slope operators coordinate with ACS to ensure that a reserve of trained manpower is available for an extended spill response.

The Qualified individual (QI) is the Incident Commander who is notified during call out of the IMT. During Tier II events, ACS North Slope resources and, if needed, Mutual Aid resources, are mobilized and deployed, as needed. During Tier III events, the QI acts as the company representative for commitment of out of region resources.

Not every incident will require formation of the Unified Command. For significant oil spills, there may be On-Scene Coordinators from the federal, state, and local governments, and COPA, as well as the responsible party, if other than COPA. These individuals will become part of the Unified Command, representing their organization as the Federal On-Scene Coordinator (FOSC), State On-Scene Coordinator (SOSC), Responsible Party (RP), and Local On-Scene Coordinator (LOSC). The North Slope Borough is the LOSC. Under provisions of the National Contingency Plan, EPA designates the FOSC for inland zone oil discharges and hazardous substance releases. For incidents involving multiple jurisdictional federal

agencies, it is the responsibility of those federal agencies to determine appropriate ICS roles and responsibilities under the Unified Command.

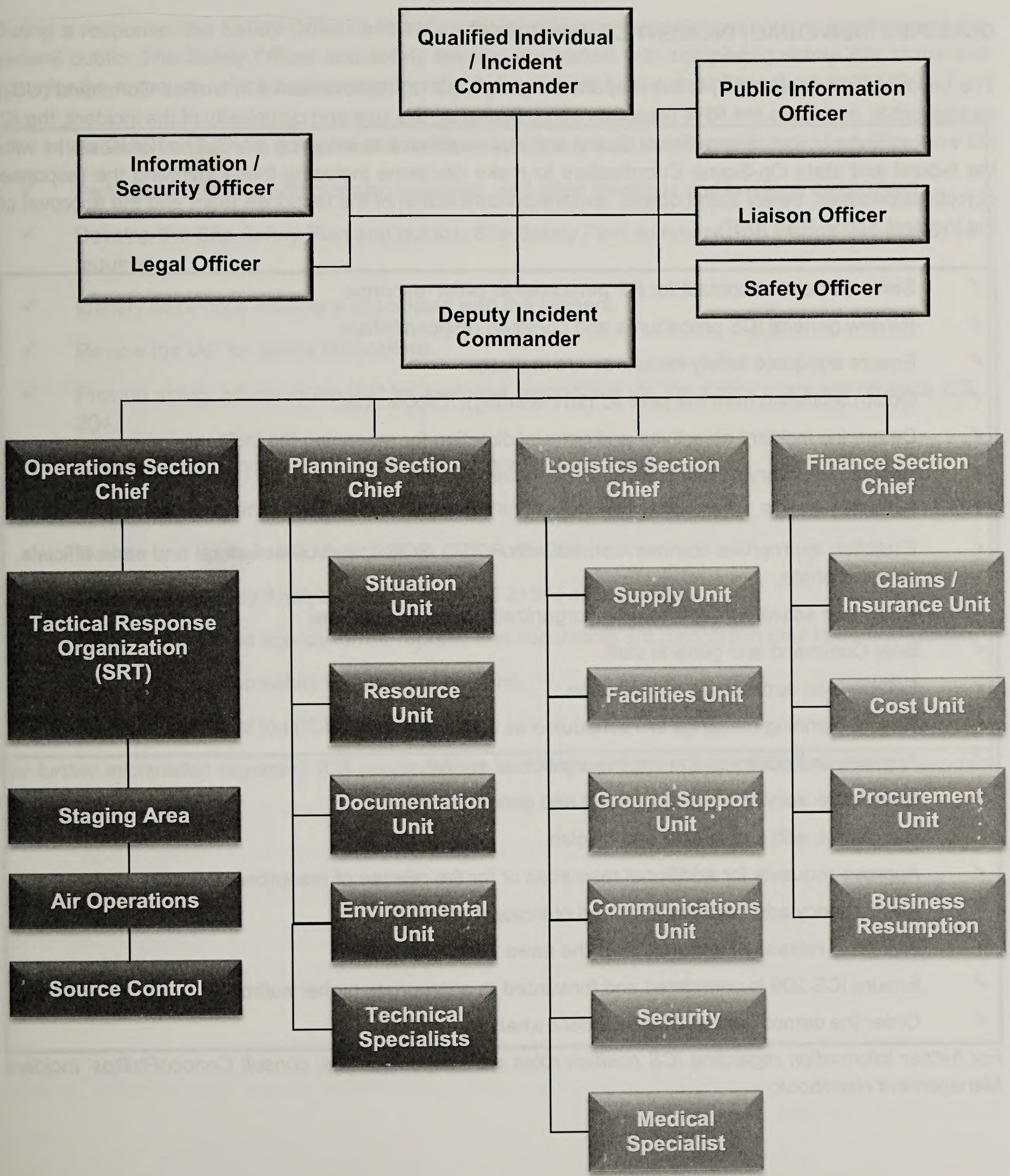
Primary responsibilities of the Unified Command are as follows:

- Determine and establish overall incident objective and response priorities,
- Review and approve tactical plans and strategies developed to address objectives and priorities,
- Ensure full integration of response resources, and
- Resolve conflicts.

The responsible party will be the Incident Commander in the Unified Command structure unless the State or Federal On-Scene Coordinator determines the response is inadequate. At that time, either the State or Federal On-Scene Coordinator will assume the Incident Commander's duties.

The QI / Incident Commander determines if needs for additional IMT personnel or resources requires activation of the ConocoPhillips Global Incident Management Assist Team (GIMAT). The GIMAT is comprised of personnel and resources from ConocoPhillips' worldwide operating business units, departments, or subsidiaries. The GIMAT may be called upon to augment or fill positions on the IMT. Activation of the Global IMAT is initiated by calling the ConocoPhillips Crisis Hotline at 1-800-342-5119.

FIGURE 3-1: INCIDENT COMMAND SYSTEM STRUCTURE



## FIGURE 3-2: IMT FUNCTIONS AND RESPONSIBILITIES CHECKLISTS

### QUALIFIED INDIVIDUAL / INCIDENT COMMANDER

The Incident Commander (IC) is the responsible party's (RP's) representative in Unified Command (UC), as applicable, and leads the RP's response effort. Based on the size and complexity of the incident, the IC will work with the United States Coast Guard and state agencies to establish a UC. The IC/UC works with the federal and state On-Scene Coordinators to make decisions including those involving the response objectives/priorities, safety stand downs, expansion/contraction of the response team and the approval of the Incident Action Plan (IAP).

| | |
|---|---|
| ✓ | Serve as point of contact for RP personnel in initial response. |
| ✓ | Review general ICS procedures and common responsibilities. |
| ✓ | Ensure adequate safety measures are in place. |
| ✓ | Obtain a briefing from the prior IC (201 Briefing), if applicable. |
| ✓ | Determine incident objectives and general direction for managing the incident. |
| ✓ | Ensure regulatory notifications have been completed. |
| ✓ | Establish an ICP. |
| ✓ | Establish appropriate communications with FOSC, SOSC, and other federal and state officials, as appropriate. |
| ✓ | Notify and activate oil spill removal organizations, as appropriate. |
| ✓ | Brief Command and general staff. |
| ✓ | Establish an appropriate organization. |
| ✓ | Ensure planning meetings are scheduled as required. |
| ✓ | Approve and authorize the implementation of an IAP. |
| ✓ | Coordinate activity for all Command and general staff. |
| ✓ | Coordinate with key people and officials. |
| ✓ | Approve requests for additional resources or for the release of resources. |
| ✓ | Keep agency administrator informed of incident status. |
| ✓ | Authorize release of information to the news media. |
| ✓ | Ensure ICS 209 is completed and forwarded to appropriate higher authority. |
| ✓ | Order the demobilization of the incident when appropriate. |

*For further information regarding ICS position roles and responsibilities, consult ConocoPhillips' Incident Management Handbook.*

## SAFETY OFFICER

During a response, the Safety Officer and safety team(s) ensure the safety of both responders and the general public. The Safety Officer and safety team(s) are tasked with completing safety ICS forms and plans for the response, which are approved by the Safety Officer before submitting them to IC/UC.

| | |
|---|---|
| ✓ | Become familiar with all applicable national, state, and local health and safety regulations. |
| ✓ | Participate in tactics and planning meetings, and other meetings and briefings as required. |
| ✓ | Develop the Site Safety Plan and publish Site Safety Plan summary (ICS Forms 201-5/208) as required. |
| ✓ | Identify hazardous situations associated with the incident. |
| ✓ | Review the IAP for safety implications. |
| ✓ | Provide safety advice in the IAP for assigned responders via the safety message on each ICS 204. |
| ✓ | Exercise emergency authority to stop and prevent unsafe acts. |
| ✓ | Investigate accidents that have occurred within the incident area. |
| ✓ | Review and approve the Medical Plan (ICS Form 206). |
| ✓ | Develop the Safety Analysis Worksheet (ICS 215A) as required. |
| ✓ | Ensure all required agency forms, reports, and documents are completion prior to demobilization. |
| ✓ | Brief Command on safety issues and concerns. |
| ✓ | Maintain individual log (ICS 214a). |

*For further information regarding ICS position roles and responsibilities, consult ConocoPhillips' Incident Management Handbook.*

## OPERATIONS SECTION CHIEF

The Operations Section Chief, a member of the General staff, is responsible for the management of all operations directly applicable to the primary objectives of the response. The Operations Section Chief is the leader of the Operations Section, which is directed by IC/UC.

| | |
|---|---|
| ✓ | Obtain briefing from IC. |
| ✓ | Request sufficient section supervisory staffing for both operations and planning activities. |
| ✓ | Identify kind and number of resources required to support selected strategies. |
| ✓ | Subdivide work areas into manageable units. |
| ✓ | Develop work assignments and allocate tactical resources based on strategy requirements. |
| ✓ | Prepare ICS 234 work analysis matrix with Planning Section Chief to ensure strategies and tactics and task are in line with ICS 202 response objectives to develop ICS 215. |
| ✓ | Participate in the planning process and the development of the tactical portions (ICS 204 and ICS 220) of the IAP. |
| ✓ | Assist with development of long-range strategic, contingency, and demobilization plans. |
| ✓ | Supervise Operations Section personnel. |
| ✓ | Monitor need for and request additional resources to support operations as necessary. |
| ✓ | Evaluate and monitor current situation for use in next operational period planning. |
| ✓ | Interact and coordinate with Command on achievements, issues, problems, significant changes, special activities, evens, and occurrences. |
| ✓ | Troubleshoot operational problems with other IMT members. |
| ✓ | Supervise and adjust operations organization and tactics as necessary. |
| ✓ | Participate in operational briefings to IMT members as well as briefings to media and visiting dignitaries. |
| ✓ | Develop recommended list of section resources to be demobilized, and initiate recommendation for release when appropriate. |
| ✓ | Receive and implement applicable portions of the incident Demobilization Plan. |

*For further information regarding ICS position roles and responsibilities, consult ConocoPhillips' Incident Management Handbook.*

## PLANNING SECTION CHIEF

The Planning Section collects, evaluates, disseminates, and uses incident information for planning operations for the next operating period and for strategic planning (long range). It maintains assigned resource status, and plans for future response activities, prepares the IAP, documents the incident response, tracks incident resources, coordinates Environmental Unit activities, oversees the display of the Situation Status Board produced by the Situation Unit, and demobilizes resources through the Demobilization Unit as necessary.

| | |
|---|---|
| ✓ | Collect, process, and display incident information. |
| ✓ | Supervise preparation of the IAP. |
| ✓ | Facilitate planning meetings and briefings. |
| ✓ | Assign personnel already on site to ICS organizational positions as appropriate. |
| ✓ | Establish information requirements and reporting schedules for Planning Section units (e.g., Resources, Situation). |
| ✓ | Determine the need for any specialized resources in support of the incident. |
| ✓ | Establish special information collection activities as necessary (e.g., weather, environmental, toxics, etc.). |
| ✓ | Assemble information on alternative strategies. |
| ✓ | Keep IMT apprised of any significant changes in incident status. |
| ✓ | Compile and display incident status information. |
| ✓ | Oversee preparation and implementation of the incident Demobilization Plan. |
| ✓ | Incorporate plans (e.g., traffic, medical, communications, site safety) in the IAP. |
| ✓ | Develop other incident-supporting plans (e.g., salvage, transition, security). |
| ✓ | Assist Operations with development of the ICS 234 work analysis matrix. |
| ✓ | Maintain Unit Log (ICS 214). |

*For further information regarding ICS position roles and responsibilities, consult ConocoPhillips' Incident Management Handbook.*

## LOGISTICS SECTION CHIEF

The Logistics Section provides necessary facilities, services, equipment, and supplies to support the incident response. The Logistics Section Chief activates and supervises the Service Branch and the Support Branch within the Logistics Section and reports directly to IC/UC as a member of the General Staff. The Logistics Section Chief coordinates with the other sections of the IMT to plan for the current and future operational periods in order to support the response objectives set by IC/UC.

- ✓ Plan the organization of the Logistics Section.
- ✓ Assign work locations and preliminary work tasks to section personnel.
- ✓ Notify the Resources Unit of the Logistics Section units activated, including names and locations of assigned personnel.
- ✓ Assemble and brief Logistics Branch Directors and Unit Leaders.
- ✓ Determine and supply immediate incident resource and facility needs.
- ✓ In conjunction with Command, develop and advise all sections of the IMT resource approval and requesting process.
- ✓ Review proposed tactics for upcoming operational period for ability to provide resources and logistical support.
- ✓ Identify long-term service and support requirements for planned and expected operations.
- ✓ Advise Command and other Section Chiefs on resource availability to support incident needs.
- ✓ Provide input and review the Communications Plan, Medical Plan, and Traffic Plan.
- ✓ Identify resource needs for incident contingencies.
- ✓ Coordinate and process requests for additional resources.
- ✓ Develop recommended list of section resources to be demobilized and initiate recommendation for release when appropriate.
- ✓ Receive and implement applicable portions of the incident Demobilization Plan.
- ✓ Ensure the general welfare and safety of Logistics Section personnel.
- ✓ Maintain Unit Log (ICS 214).

*For further information regarding ICS position roles and responsibilities, consult ConocoPhillips' Incident Management Handbook.*

## FINANCE SECTION CHIEF

The Finance Section manages financial aspects of the incident response, including tracking the incident cost, processing invoices and payments, paying claims, and negotiating vendor contracts and pricing. The Finance Section Chief, a member of the General Staff, leads the Finance Section and is directed by IC/UC. The Finance Section Chief activates and supervises the Time/Cost Unit, the Procurement Unit, and the Compensation/Claims Unit, when necessary.

- ✓ Participate in incident planning meetings and briefings as required.
- ✓ Review operational plans and provide alternatives where financially appropriate.
- ✓ Manage all financial aspects of an incident.
- ✓ Provide financial and cost analysis information as requested.
- ✓ Gather pertinent information from briefings with responsible agencies.
- ✓ Develop an Operating Plan for the Finance/Admin Section; fill supply and support needs.
- ✓ Determine the need to set up and operate an incident commissary.
- ✓ Meet with assisting and cooperating agency representatives, as needed.
- ✓ Maintain daily contact with agency(ies) administrative headquarters on finance/admin matters.
- ✓ Ensure all personnel time records are accurately completed and transmitted to home agencies, according to policy.
- ✓ Provide financial input to demobilization planning.
- ✓ Ensure all obligation documents initiated at the incident are properly prepared and completed.
- ✓ Brief agency administrative personnel on all incident-related financial issues that require attention or follow-up prior to leaving the incident.
- ✓ Develop recommended list of section resources to be demobilized and initial recommendation for release when appropriate.
- ✓ Receive and implement applicable portions of the incident Demobilization Plan.
- ✓ Maintain Unit Log (ICS 214).

*For further information regarding ICS position roles and responsibilities, consult ConocoPhillips' Incident Management Handbook.*

## 3.4 REALISTIC MAXIMUM RESPONSE OPERATING LIMITATIONS [18 AAC 75.425(e)(3)(D)]

### 3.4.1 Introduction

Realistic maximum response operating limitations that might be encountered at the facility are described in the ACS *Technical Manual*, Volume 1, Tactics Description L-7, which is incorporated into the plan by reference. Tactic L-7 analyzes the frequency and duration, expressed as a percentage of time, of limitations that would render mechanical response methods ineffective, as required by 18 AAC 75.425(e)(3)(D). The analysis considers weather, sea conditions, ice, daylight hours, and other environmental conditions that might influence the efficiency of the oil spill response.

Broken ice conditions limit mechanical oil containment boom and recovery skimmers. As ice coverage increases, it becomes more and more difficult to maintain containment boom configurations and skirts to concentrate oil for recovery. Field tests in July 2000 demonstrated the effects of broken ice on a containment boom system (Bronson, 2002). However, broken ice conditions can promote oil removal by in situ burning. Alternative response measures may reduce environmental consequences of a spill when environmental conditions exceed operating limits. In high wind-chill conditions staff may be added to allow longer warm-up break times. When ground visibility or road transportation is limited by weather, conditions may allow flights for transportation and surveillance. Tracked vehicles and airboats or low-draft vessels can transit meltwater, snow and ice surfaces that preclude wheeled traffic. In sea states that preclude oil containment and recovery, vessels are still able to transit. When night hours otherwise restrict visibility, light plants can be used.

### 3.4.2 Weather and Ice Conditions During the Shoulder Seasons

The following general description of break-up and freeze-up applies to the marine environment in the Prudhoe Bay region. Descriptions are of typical conditions. They cover the chronology of break-up and freeze-up. See Vaudrey and Dickins et al. (2000) and tables in Atwater (1991) for further site-specific details.

**May**

The Sagavanirktok River and Kuparuk River overfloods (Condition 5) commence on average May 20 and 27, respectively, based on 16 years of analysis. See DF Dickins Associates et al. (2001) for descriptions of seasonal ice conditions.

**June**

June 1-10: Landfast ice is intact (Condition 4) beyond the Kuparuk River and Sagavanirktok River overflood boundaries. Within the overflood zones immediately off the river deltas, fast ice lifts off the bottom of the Beaufort Sea and rapidly melts in place from the relatively warm water discharge (Conditions 6 and 7). The peak of major flooding occurs during the period June 4-7 (±6 days), at which point the Kuparuk River overflood may reach within 1 mile of the Northstar Island (Condition 5). Routine ice road operations might cease at this time. First open water appears offshore of the Sagavanirktok River and Kuparuk River by June 6 to 13, respectively, on average. Fast ice beyond the overflood zones and outside the barrier islands is still intact and more than 5 feet thick in early June.

June 15-20: Nearshore lagoon areas affected by the Kuparuk overflood and shallow waters off the Sagavanirktok delta become mostly free of ice (Condition 9). Fast ice offshore remains intact (e.g., Stump Island to Northstar) and continues to melt (Condition 7). Solid ice 4 to 5 feet thick still surrounds Northstar Island. The soft surface is 25 percent covered by melt water pools (Condition 6).

Air temperatures average 35°F and range from 20°F to 40°F. The wind is variable, but blows 60 percent of the time from the east and northeast, averaging 10 knots.

The ice can support response vehicles up to several weeks before break-up. The effect of deteriorating sea ice on access with specific equipment is illustrated in ACS *Technical Manual,* Tactic L-7, based on field trials by Coastal Frontiers (2001).

**July, August, and September**

July 1: A completely intact, deteriorated ice cover 3 to 4 feet thick, with many cracks and approximately 40 percent to 50 percent of its surface covered by melt pools and holes still exists in deeper water in the vicinity of Northstar (Condition 6).

July 4 (Typical): Break-up begins with fracturing and movement in the floating landfast ice (Condition 7).

July 8-12: Remaining fast ice outside the barrier islands, off the Sagavanirktok River delta and in Prudhoe Bay, decreases to less than seven-tenths coverage (Condition 8).

July 15-26: Open, ice-free water out to Northstar and surrounding West Dock and Endicott causeway (Condition 9).

Air temperatures average 40°F in July.

The median number of days with flooded and/or broken ice at break-up at production facilities range from 12 days at Point McIntyre, to 22 days at Northstar.

**October**

October 4, ±8 days: Freeze-up begins along shore in shallow water. Ice becomes shorefast for the season within one week following freeze-up in the nearshore lagoons (e.g., Point McIntyre 2 and Niakuk) and by October 25 offshore.

Additional time is required for the young ice sheet to gain sufficient thickness and stability to be judged safe for over-ice operations. Time from initial freeze-up to being able to commence on-ice operations with response equipment ranges on average from 40 to 43 days at coastal or nearshore locations such as Point McIntyre 1, Niakuk, and Endicott, to 55 days at Northstar.

Air temperatures at freeze-up range from 5°F to 15°F. Daylight is 9 to 10 hours per day.

### 3.4.3 In Situ Burning Response Measures to Reduce Environmental Consequences of a Spill in Ice Conditions

Section 1.7 provides information about permits and approval required for in situ burning. Oil spill removal during the shoulder seasons can be greatly enhanced by in situ burning. Cold water slows weathering processes, which increases the timeframe window of opportunity for burning, and ice provides containment

to concentrate oil for burning and recovery. In situ burning in shoulder-season ice conditions generally involves selective burning of oil on melt pools and in leads between floes, followed by manual recovery of residue.

**Operational Capability for In Situ Burning in Ice**

ACS maintains an inventory of specialized equipment for in situ burning operations during shoulder-season ice conditions.

ACS *Technical Manual*, Tactics B-1 through B-7 describe planning, response strategies, procedures, and equipment to implement a successful burn in a mix of solid ice, broken ice, and open water situations. The tactics descriptions are listed below and are incorporated by reference into the plan.

- B-1 In Situ Burning Plan,
- B-2 Burning Oily Vegetation
- B-3 In Situ Burning with Helitorch and Other Igniters,
- B-4 Deployment and Use of Fire Containment Boom,
- B-5 Burning Oil Pools on any Solid Surface,
- B-6 Residue Recovery, and
- B-7 Burn Extinguishment on Water (applicable to fire booms in light ice cover).

ACS conducts spill response training courses involving classroom and field exercises at North Slope locations to practice the burn tactics in the ACS *Technical Manual* . The training involves a classroom course and a field demonstration with burn plans. The helitorch is discussed in the classroom and shown in the warehouse. Demonstrations can also involve creating and igniting gelled fuel. Alyeska Pipeline Service Company has pilots familiar with the helitorch operations and its helicopter is set up for the helitorch attachment.

The ACS inventory of specialized response equipment on hand to support a large-scale burning operation is summarized in Table 3-3.

**TABLE 3-3: BURNING EQUIPMENT**

| EQUIPMENT | QUANTITY |
|---|---|
| Helitorch (55 gallons) | 6 |
| Air deployable igniters | 1,436 |
| Helitorch batch gel mixers | 2 |
| Adapted from ACS inventory – Response Equipment Specifications, ACS Technical Manual, Tactic L-6. | |

In addition, ACS maintains fire-resistant boom in a mix of sizes (20-, 30- and 42-inch skirts), together with specialized logistics vehicles to access spill sites over a rotting and/or flooded ice surface in May and June (e.g., shallow draft boats). See Tactic L-6 tables describing boom and vessels.

Steps in the decision to use in situ burning are summarized in the ACS *Technical Manual* Tactic B-1. Before using in situ burning, regulatory approval is obtained by first completing the ARRT Application for In Situ Burning and submitting it to the Unified Command according to ARRT's Unified Plan, Annex F, Appendix II, "In Situ Burning Guidelines for Alaska,". The application contains the incident-specific burn plan.

Once state and federal approval is granted, the following steps are taken to implement the response:

- Collect and concentrate the oil using fire-resistant booms in light ice cover or utilize naturally occurring pools of thicker oil in high-ice concentrations and on surface melt pools on solid ice break-up, and in slush and new ice at freeze-up.
- Ignite the oil using the helitorch or hand-held igniters, following established safety procedures to avoid flashback or ignition of any ongoing spill source.
- Monitor the burn, maintaining constant watch on the fire and smoke plume, condition of containment booms (if used), and other safety hazards and issues.
- Recover and dispose of the burn residue.

Safety procedures and planning in accordance with established guidelines are emphasized throughout the training, preparation, and conduct of in situ burning operations. In situ burns are monitored to ensure that fire does not spread to adjacent combustible material. Care is taken to control the fire and to prevent secondary fires. Personnel and equipment managing the process are protected. The safe working distances from an in situ fire on water depend on the size of the fire and the exposure time. Aerial ignition with gel by helitorch or other ignition methods is coordinated, taking into account prevailing weather conditions, oil pool size, and distribution and the need for strict adherence to established safety distances. Effectiveness of In Situ Burning in Ice

The consensus of research on spill response in broken ice conditions is that in situ burning is an effective response technique with removal rates exceeding 85 percent in many situations (Shell et al., 1983; SL Ross, 1983; SL Ross and DF Dickins, 1987; Singsaas et al., 1994). A considerable amount of research has demonstrated in situ burning in broken ice. The research includes several smaller-scale field and tank tests (SL Ross et al., 2003; Shell et al., 1983; Brown and Goodman, 1986; Buist and Dickins, 1987; Smith and Diaz, 1987; Bech et al., 1993; Guénette and Wighus, 1996) and one large field test (Singsaas et al., 1994). Most of the tests involved large volumes of oil placed in a static test field of broken ice resulting in substantial slick thicknesses for ignition. The few tests in unrestricted ice fields or in dynamic ice have indicated that the efficacy of in situ burning is sensitive to ice concentration and dynamics and thus the tendency for the ice floes to naturally contain the oil, the thickness (or coverage) of oil in leads between floes, and the presence or absence of brash or frazil ice which can absorb the oil.

Brash ice is the debris created when larger ice features interact and degrade. Frazil ice is the “soupy” mixture of very small ice particles that forms as seawater freezes.

Oil spilled on solid ice or among broken ice in concentrations equal to or greater than six-tenths has a high probability of becoming naturally contained in thicknesses sufficient for combustion. In lower ice concentrations, oil spill response methods can be used to create and maintain sufficient film thickness to facilitate burning. Fire-resistant booms are examples. Field experience has shown that it is the small ice pieces (e.g., the brash and frazil, or slush, ice) that accumulate with the oil against the edges of larger ice features (floes) and control the concentration (e.g., thickness) of oil in an area, and control the rate at which the oil subsequently thins and spreads. Other factors affecting burn effectiveness include oil weathering processes (e.g., evaporation and emulsification) and mixing energy from waves.

The following discussion summarizes the current state of understanding the scientific principles and physical processes involved in situ burning of oil on melt pools during the ice-melt phase in June or on water between floes during the break-up period in July, based on SL Ross et al. (2003). Further discussion

also covers in situ burning of thinner slicks in mobile broken ice comprised of brash or frazil ice during the freeze-up shoulder season in October.

The success of an in situ burning operation is dependent on the thickness of the oil to be burned. Ignition and burn efficiency are highly dependent on slick thickness.

For an oil slick on water or ice to become ignited, the oil must be thick enough to insulate itself from the water beneath it. The igniter can heat the surface of thickened oil to the flash point temperature at which the oil produces sufficient vapors to ignite. The rules of thumb for minimum ignition thickness are listed in Table 3-4.

### TABLE 3-4: MINIMUM IGNITABLE THICKNESS ON WATER

| OIL TYPE | MINIMUM THICKNESS |
|---|---|
| Light crude and gasoline | 1 millimeter (0.04 inch) |
| Weathered crude and middle-distillate fuel oils (diesel and kerosene) | 2 to 3 millimeter (0.08 to 0.12 inch) |
| Residual fuel oils and emulsified crude oils | 10 millimeter (0.4 inch) |

The oil removal rate for in situ oil fires is a function of fire size (or diameter), slick thickness, oil type, and ambient environmental conditions. For most large (greater than 3 meters in diameter) fires of unemulsified crude oil on water, the “rule-of-thumb” is that the burning consumption rate is 3.5 millimeters per minute. Lighter fuels burn faster, and heavier oils and emulsions burn slower, as shown in Table 3-5.

Burn rate is also a function of the size of the fire. Crude oil burn rates increase from 1 millimeter per minute with 3-foot diameter fires, to 3.5 millimeters per minute for 15-foot fires and greater. In situ burns on melt pools typically consume oil at 1 millimeter per minute. For very large fires, on the order of 50 feet in diameter and larger, burn rates may decrease slightly because there is insufficient air in the middle of the fire to support combustion at 3.5 millimeters per minute. As fire size grows to the 50-foot range, oil type ceases to affect burn rate for the same reason.

### TABLE 3-5: BURN/REMOVAL RATES FOR LARGE FIRES ON WATER

| OIL TYPE / CONDITION | BURN / REMOVAL RATE |
|---|---|
| Gasoline >10 millimeters (0.4 inch) thick | 4.5 millimeters per minute (0.18 inch per minute) |
| Distillate fuels (diesel and kerosene) >10 millimeters (0.4 inch) thick | 4.0 millimeters per minute (0.16 inch per minute) |
| Crude oil >10 millimeters (0.4 inch) thick | 3.5 millimeters per minute (0.14 inch per minute) |
| Heavy residual fuels >10 millimeters (0.4 inch) thick | 2.0 millimeters per minute (0.08 inch per minute) |
| Slick 5 millimeters thick* | 90 percent of rate stated above |
| Slick 2 millimeters thick* | 50 percent of rate stated above |
| Emulsified oil (percent of water content)** | Slower than above rates by a factor equal to the water content percent |
| Estimates of burn/removal rate based on experimental burns and should be accurate to within ±20 percent. | |

* Thin slicks will naturally extinguish, so this reduction in burn rate only applies at the end of a burn.

** If ignited, emulsions will burn at a slower rate almost proportional to their water content (a 25 percent water-in-crude-oil emulsion burns about 25 percent slower than the unemulsified crude).

An in situ oil fire is extinguished naturally when the slick burns down to a thickness that allows enough heat to pass through the slick to the water to cool the surface of the oil below the temperature required to sustain

combustion. The thickness at which an oil fire on water extinguishes is related to the type of oil and initial slick thickness. The rules of thumb are presented in Table 3-6. Other, secondary factors include environmental effects such as wind (winds greater than 20 knots preclude in situ burning in most cases), current herding of slicks against barriers, and oil weathering.

### TABLE 3-6: FIRE EXTINGUISHING SLICK THICKNESS

| OIL TYPE/INITIAL SLICK THICKNESS | EXTINGUISHING THICKNESS |
|---|---|
| Crude oil up to 20 millimeters (0.8 inch) thick | 1 millimeter (0.04 inch) |
| Crude oil 50 millimeters (2 inches) thick | 2 to 3 millimeters (0.08 to 0.12 inch) |
| Distillate fuels any thickness | 1 millimeter (0.04 inch) |

With an estimate of the initial thickness of a fully contained slick, or a measure of the burn time, it is relatively easy to estimate oil removal efficiency by burning. If not all the slick area is on fire; the calculations need to account for this.

Oil removal efficiency by in situ burning may be summarized as a function of the following key factors:

- Initial thickness of the slick,
- Thickness of the residue remaining, and
- Amount of the slick's surface that was on fire.

The water current maintains the oil thickness in the apex of a fire-resistant boom under tow, or against an ice edge in wind or current. When burning in a current, the fire slowly decreases in area until it reaches a size that can no longer support combustion. This herding effect can increase overall burn efficiencies, but it extends the time required to complete each burn.

The residue from a typical, efficient (greater than 85 percent removal) in situ burn of crude oil 10 to 20 millimeters thick is a semi-solid, tar-like layer that has an appearance similar to the skin on an old, poorly-sealed can of latex paint that has gelled. For thicker slicks, typical of what might be expected in a towed fire boom (about 150 to 300 millimeters), the residue can be a solid. Burn residue is usually denser than the original pre-burn oil, and usually it does not spread due to its increased viscosity or solid nature.

Tests indicate that the burn residues from efficient burns of heavier crude oils less than 32 degrees API gravity may sink once the residue cools, but their acute aquatic toxicity is very low or nonexistent. The "In Situ Burning Guidelines for Alaska," state:

> "In general, however, the effects [of burn residue in that floats or sinks] are less severe than those from a large, uncontained oil spill, and no specific biological concerns have been identified to date."

Compared with unemulsified slicks, emulsions are much more difficult to ignite and, once ignited, display reduced flame spreading and more sensitivity to wind and wave action. Stable emulsion water contents are typically in the 60 percent to 80 percent range with some up to 90 percent. The oil in the emulsion cannot reach a temperature higher than 100°C until the water is either boiled off or removed. The heat from the igniter or from the adjacent burning oil is used first mostly to boil the water rather than heat the oil.

The following points summarize the effect of water content on the removal efficiency of weathered crude emulsions:

- Little effect on oil removal efficiency (i.e., residue thickness) for water contents up to about 12.5 percent by volume;
- A noticeable decrease in burn efficiency with water contents above 12.5 percent, the decrease being more pronounced with weathered oils;
- Zero burn efficiency for emulsion slicks having water contents of 25 percent or more; and
- Some crudes form meso-stable emulsions that can burn efficiently at much higher water contents. Paraffinic crudes appear to fall into this category.

Fortunately, emulsion formation is slowed dramatically by high ice concentrations and may not be a significant operational factor in planning in situ burns on solid ice or naturally contained in higher concentrations of broken ice.

SL Ross et al. (2003) provides guidelines for burning thin slicks in broken ice with brash and slush, particularly relevant during the break-up and freeze-up shoulder seasons. General rules for minimum ignitable thickness and oil removal rates for burning thin slicks of crude oils on brash and/or slush with broken ice are as follows:

- The minimum ignitable thickness for fresh crude on frazil ice or small brash ice pieces is up to double that on open water, or about 1 to 2 millimeters.
- The minimum ignitable thickness for evaporated crude oil on frazil ice or small brash ice pieces can be higher than on open water, but is still within the range quoted for weathered crude on water, about 3 millimeters with gelled gasoline igniters.
- For a given spill diameter, the burn rate in calm conditions is about halved on relatively smooth frazil/slush ice and halved again on rougher, brash ice. Wave action slightly reduces the burn rate on open water, but the halving rule seems to apply in waves as well.
- The residue remaining on broken ice in calm conditions is about 50 percent greater than that on open water, or 1.5 millimeters. The residue remaining on brash or frazil ice in waves is slightly greater than in calm conditions, at about 2 millimeters.

In summary, in situ burning of oil is efficient and rapid in broken ice conditions under the following conditions:

- The spilled oil is thicker than the minimum ignitable (a thickness of 2 to 3 millimeters results in 50 to 66 percent removal efficiency: 10-millimeter thickness, a typical thickness for wind-herded slicks on melt ponds on ice, gives 90 percent removal efficiency);
- Larger areas can be ignited (a 100-square-foot slick on a melt pool will burn at 3.5 barrels of oil per hour, a 50-foot diameter, 10-millimeters thick slick will burn at 300 barrels of oil per hour, and a 100-foot diameter slick will burn at 1,200 barrels of oil per hour); and
- The oil is not more than 25 percent emulsified.

### 3.4.4 Environmental Conditions

The realistic maximum response operating limitations are described in the ACS *Technical Manual* (Tactic L-7). Environmental conditions can sometimes limit response work. Some limitations are based on safety, and others concern equipment effectiveness. The ACS *Technical Manual* lists the percentage of time some variables reduce effectiveness of response for planning purposes.

Low visibility due to fog or heavy snow is an environmental condition that can limit the effectiveness of a response. Low visibility can affect transportation as well as visual pipeline leak detection and spill tracking.

The most limiting factors of mechanical containment and response effectiveness at Alpine are the remote location and the lack of road access in the event of a blowout (except when an ice road is in place). An open-orifice blowout to a remote, roadless area presents a difficult response because of the volume of oil to be contained without a road-supported response. Major factors affecting the response to a blowout in a roadless area are as follows:

- **Storage Removal**: Without vehicles and vacuum trucks accessing the site at collection points, a major advantage of mass storage removal is removed from the response. The collection sites must be accessed with smaller collection units, i.e., tundra travel vehicles or airboats. Other removal options include large quantities of transfer pumps and hoses or burning at the collection points.
- **Vessel Access**: The Colville River delta presents a unique response environment with its many channels, dead arms, sloughs and isolated lakes. Passage in many of the channels is variable. Airboats are the best vessel for use in the river channels of the delta.
- **Break-up Flooding**: A spring break-up flooding event usually occurs every year in the delta. High river discharge along with ice would complicate a response activity. The high water may make navigation in the channel easier, but it would disperse the oil rapidly and in an erratic manner, and ice conditions may limit the effectiveness of boom containment and skimmer operation. Break-up flows last for approximately three weeks.

COPA and North Slope spill responders plan to respond to all reported spills, including all those in spring break-up conditions. Responders evaluate the spill and do everything humanly possible to contain, control, and clean up the spill without jeopardizing personal safety. Break-up conditions do not preclude any oil spill responses at Alpine, although they may limit the effectiveness of responses.

## 3.4.5 Colville River Delta

Realistic maximum response operating limitations descriptions, called for in 18 AAC 75.425(c)(3)(D), are incorporated into this plan by reference to the ACS *Technical Manual* Tactic L-7. The Tactic L-7 descriptions of water and ice conditions of the Colville River in the spring are based on the U.S. Army Corps of Engineers report for the Endicott Environmental Monitoring Project. Tactic L-7 outlines the amount of time and typical dates that break-up conditions could reduce the effectiveness of mechanical response in the Colville River and its vicinity, as follows:

- In the lagoon, broken ice concentrations limiting the effectiveness of oil recovery by vessels may last a week.
- Ice in the Colville River may limit response effectiveness for 13 days typically.
- Over-ice flow of Colville River water may limit responses for 12 days typically.
- High water flows in the rivers may limit response effectiveness for two to three weeks typically.

Responses are not precluded during these dates.

The Colville River's median date of peak break-up discharge is June 2. For about three weeks centered on the peak flow date, some overflow, ice movement, and ice pile-up are expected to reduce the effectiveness

of mechanical oil spill response. In situ burning is an important non-mechanical response that can be effective and can be conducted safely by response personnel.

Examples of break-up conditions that may reduce the effectiveness of mechanical response are as follows:

Sheetflow Periods

Oil spill containment and removal in sheetflow conditions may involve in situ burning of oil, as well as booming and barriers. See ACS *Technical Manual* Tactics B-1 through B-5 and C-1 through C-5.

Ice Pile-up in the Colville River Delta

The Nigliq Channel Bridge and in-field piping crossings over channels of the delta are designed to withstand and break through ice jamming and loading events. However, broken ice, ice jams, and floodwaters in the Colville River and other channels of the delta threaten response worker safety and limit response effectiveness during break-up. Workers do not deploy response equipment on water at times and locations that are unsafe for them, including some aggressive break-up conditions. In situ burning is an important response options under these conditions.

Broken Ice in Rivers and Channels

During aggressive break-up in rivers and channels of the Colville River delta, when freshwater ice breaks loose and begins floating downstream, tactical spill response options are limited. Strong currents and large pieces of ice make conditions unsafe for airboat or other vessel deployment. Due to elevated safety risks to personnel, containment and/or recovery equipment may not be able to be deployed in river channels. During this time, alternative mechanical recovery or burning strategies are used in quiet-water areas downstream of the spill. See ACS *Technical Manual* Tactic R-12.

Broken Ice in the Lagoon

Conventional on-water containment and recovery is affected by ice concentrations greater than 30 percent coverage. At ice concentrations greater than 70 percent, on-water recovery effectiveness becomes limited (see the Deployment Considerations and Limitations statement in the ACS *Technical Manual* Tactics R-19A and L-7).

River Water Overflows onto the Shore-fast Lagoon Ice

Over-flooding limits mechanical response effectiveness. In situ burning is an important response option for over-flood conditions. See ACS *Technical Manual* Tactics L-7, B-1, B-3, and B-5.

Ice Pile-up at the Pipeline Transitions at the Colville River

The pipeline's exit points from its transition under the Colville River lie approximately 6 inches below the 200-year flood stage elevation and are not expected to experience river ice pile-up. This means that only 6 inches of water would be expected, at worst case, during a 200-year event to cover the pad and surround the point where the pipeline exits the ground. Six inches of water is not capable of carrying significant quantities of ice. As such, a pile-up condition cannot be created.

Examples of freeze-up conditions that may reduce the effectiveness of mechanical response are as follows:

Freezing Rivers, Ponds, and Lakes

Low water flow is characteristic of Alpine-area hydrology during freeze-up and into the winter when rivers, ponds, and lakes freeze over and shallow ponds and lakes freeze to the bottom (Section 3.2). Aggressive

ice pile-ups or ice jams are not expected; however, resources would be expended on ice management in water bodies to reduce the risk of boom failure and limit safety concerns. As ice coverage increases, it becomes more difficult to operate containment boom to concentrate oil for recovery from open water. Operation of some skimmers may be reduced. Aufeis formations may be present downstream of local freshwater springs or along shorelines. Safety or operational restraints on response activities on thin or new-forming ice and aufeis would limit response effectiveness. Additional response limitations during freeze-up are discussed in the ACS *Technical Manual*.

### 3.4.6 Fish Creek Basin

The Fish Creek Basin is a relatively large drainage basin consisting of lakes and three significant tributary basins: Inigok Creek, Judy Creek, and Tinmiaqsiugvik (Ublutuoch) River. The Tinmiaqsiugvik River enters Fish Creek approximately 10 miles upstream from its mouth; portions of the river are entrenched, which creates narrower floodplains and steeper river banks. Fish Creek Basin streams have relatively low gradients and highly sinuous channels (BLM, 2004). Channel surveys of the Tinmiaqsiugvik River show general water depths of 5 feet, which allows access and navigation by shallow draft vessel (ConocoPhillips, 2005).

Floodplain Inundation

Spring break-up occurs in the Tinmiaqsiugvik River during the first week in June, with peak stages noted between June 5 and 8 (BLM, 2004). Flooding and high water conveyance along the Tinmiaqsiugvik River at break-up occurs within the lower west floodplain during periods of high flow and/or when ice occurs in the main channel; the east and upper west floodplains are also inundated but convey little flow (BLM, 2004). Oil spill containment and removal in flood conditions may involve in situ burning of oil, as well as booming and barriers. See ACS *Technical Manual* Tactics B-1 through B-5 and C-1 through C-5. Workers do not deploy response equipment on water at times and locations that are unsafe for them, including some aggressive break-up conditions. In situ burning is an important response options under these conditions.

Snow and Ice in Channels

In Fish and Judy Creeks, observations made during the 2001 spring break-up indicate that snow and ice influence the shape and size of the channel cross-section, cause ice jams, and affect hydraulic roughness (BLM, 2004). For the Tinmiaqsiugvik River, the main channel may be entirely blocked by snow and ice and from the start of break-up flow until late June, when the water gradually cuts through the snow and ice until it reaches the permanent channel bed. During this time, the snow and ice dramatically impact the channel shape, size, and elevation, the hydraulic roughness, and the energy slope. Peak water surface elevation and discharge occurs in early June, during which time, flow is conveyed on snow, well above the permanent riverbed (BLM, 2004). River overflow on ice conditions, broken ice, and ice jams, threaten response worker safety and may limit response effectiveness; containment and/or recovery equipment may not be able to be deployed in river channels. Strong currents and large pieces of ice make conditions unsafe for vessel deployment and may interfere with boom systems. Alternative mechanical recovery or burning strategies are used in quiet-water areas.

## 3.5 LOGISTICAL SUPPORT [18 AAC 75.425(e)(3)(E)]

COPA has an existing logistical support infrastructure for its operations on the North Slope. Transportation equipment, operational coordination procedures, and maintenance procedures are in place under normal operating conditions. COPA has contracts for operational logistics to support a spill response. Additionally, ACS maintains contracts with various vendors, which, as a member of ACS, COPA may utilize during a spill response.

ACS *Technical Manual,* Volume 1, Tactics L-3, L-4, L-6, and L-8 through L-10 are incorporated here by reference.

## 3.6 RESPONSE EQUIPMENT [18 AAC 75.425(e)(3)(F)]

### 3.6.1 Equipment Lists

Contracted or other oil discharge containment, control, cleanup, storage, transfer, lightering, and related response equipment to meet the applicable RPS presented in Part 1, and to protect environmentally sensitive areas and areas of public concern described in Part 3, and that may be reasonably expected to suffer an impact from a spill of the RPS volume as described in the response Scenarios in Section 1.6 is listed in the ACS *Technical Manual,* Volume 1 under relevant tactics. The location, inventory, and ownership of the equipment is listed in ACS *Technical Manual* under relevant tactics and/or Tactic L-6. The timeframe for delivery (mobilization) and startup (deployment) of response equipment and trained personnel is outlined in the response scenarios in Section 1.6. Manufacturer's rated capacities, limitations, and operational characteristics for oil recovery equipment listed in the response scenarios are described in ACS *Technical Manual* under relevant tactics and/or Tactic L-6. Each vessel and the equipment for transferring oil from tanks mentioned in the scenarios in Part 1 is listed in Tactic L-6 as well.

Alpine has dedicated oil spill response equipment positioned throughout the field in conexes and storage areas. The general equipment locations are shown in Figure 3-3. Pre-staged equipment and support infrastructure are also illustrated in ACS *Technical Manual,* Volume 2, Map Atlas Sheets 8, 9, 12, 16, 17, 18, 20, 21, 22, 23, 23A, 24, 27, and 121. With each year's experience in operating in the Alpine area, the staging of equipment and sites will vary. Alpine spill response equipment is maintained by ACS who can provide the most current and up-to-date equipment inventory and their locations, including remote and pre-staged locations. The Alpine response equipment list is available upon request.

In addition to the dedicated spill response equipment at Alpine, there is other equipment located on site that would be available in the event of a spill. Heavy equipment maintained at Alpine drilling and production operations typically includes a forklift with snow bucket attachment, front-end loaders, Supersucker, 14G grader, backhoe, vacuum trucks, Maxi Haul, lube truck, mechanics truck, water truck, fuel truck, bobcat with trimmer, semi and trailer, avgas trailer, and portable storage tanks. Sandbags are also available on site. Additionally, tundra travel vehicle support may be on site during drilling and production operations. Equipment can be used for berm construction, trenching, direct suction and storage, and other spill response operations, if needed.

### 3.6.2 Pre Staged and Pre Deployed Response Equipment

Spill prevention and response measures for the Alpine area includes several sites with pre-staged equipment and pre-deployed boom. Equipment is pre-staged at strategic locations either year-round or seasonally, during summer months. Boom is seasonally pre-deployed in diversionary and exclusion boom configurations immediately downstream of major pipeline crossings and at other pre-designated strategic locations along river channels and streams (see ACS *Technical Manual* Tactics C-8 and C-9 for typical boom configurations). With each year's experience in operating in the Alpine area, the staging sites and deployment of equipment may vary. The goal is to strategically locate staged equipment in close proximity to potential leak sources, at likely containment sites, and in areas that are easily accessible so additional equipment can be quickly deployed, if needed. Additional boom deployment sites may be evaluated during an actual event. In addition to pre-deployed boom and response equipment, channel markers are annually deployed in major channels to assist responders in vessel navigation.

Due to seasonal changes of the river channels and weather conditions causing fluctuating river currents, specific boom configurations and exact lengths of boom pre-deployed may vary. At each pre-deployment

site, sufficient boom sections and anchors are utilized to traverse the water body in a manner that optimizes its intended use for containment, diversion, exclusion, and/or recovery. Pre-staged equipment and pre-deployed boom locations are described in Table 3-7.

The open-water time frame for seasonal boom deployment activities follows spring break-up each year, typically occurring around early to mid-June on the Colville River and mid-to-late June on surrounding rivers, and ends prior to the fall freeze-up (typically in mid-September). Some pre-staged equipment locations are also seasonally deployed each year. If possible, seasonally pre-staged equipment deployment is conducted in late May to early June. Initial boom pre-deployment at all sites is estimated to take approximately two weeks. Prior to fall freeze-up, all pre-deployed response equipment is removed , cleaned, repaired, and returned to the appropriate storage location.

### TABLE 3-7: ALPINE PRE-STAGED AND PRE-DEPLOYED EQUIPMENT SITES

| NAME | LOCATION | EQUIPMENT | RESPONSE STRATEGY |
|---|---|---|---|
| ALP-1 | North of Alpine Pipeline crossing of the Miluveach River | Pre-staged equipment and seasonally pre-deployed boom | Deflect oil toward bank for recovery; Tactic C-8. |
| ALP-2 | North of Alpine Pipeline crossing of the Kachemach River | Pre-staged equipment and seasonally pre-deployed boom | Deflect oil toward bank for recovery; Tactic C-8. |
| ALP-3 | East bank of Colville River north of Alpine Pipeline below grade crossing | Pre-staged equipment | Deflect oil toward bank for recovery; Tactic C-8. |
| ALP-5 | West bank of Sakoonang Channel southeast of CD4 pad | Pre-staged equipment | Deflect oil toward bank for recovery; Tactic C-8. Exclusion booming; Tactic C-9. |
| ALP-9 | East bank of Nigliq Channel north of CD2 pad | Pre-staged equipment | Deflect oil toward bank for recovery; Tactic C-8. |
| ALP-10 | South bank at hairpin turn of Sakoonang Channel north of CD1 pad | Pre-staged equipment | Deflect oil toward bank for recovery; Tactic C-8. |
| ALP-12 | West bank of Kachemach River south of three finger fork | Seasonally pre-staged equipment | Deflect oil toward bank for recovery; Tactic C-8. |
| ALP-13 | West bank of Miluveach River south of confluence with Colville River | Seasonally pre-staged equipment | Deflect oil toward bank for recovery; Tactic C-8. |
| ALP-14 | North bank of Sakoonang Channel downstream of CD3 pipeline crossing | Pre-staged equipment | Deflect oil toward bank for recovery; Tactic C-8. |
| ALP-15 | West bank of Tamayagiak Channel upstream of Ulamnigiaq fork | Seasonally pre-staged equipment and seasonally pre-deployed boom | Deflect oil toward bank for recovery; Tactic C-8. |
| ALP-16 | North bank of Tamayagiak Channel downstream of southern CD3 pipeline crossing | Pre-staged equipment and seasonally pre-deployed boom | Deflect oil toward bank for recovery; Tactic C-8. |
| ALP-17 | North bank of Ulamnigiaq Channel downstream of northern CD3 pipeline crossing | Pre-staged equipment and seasonally pre-deployed boom | Deflect oil toward bank for recovery; Tactic C-8. |
| ALP-18 | CD3 pad | Pre-staged equipment | Deflect oil toward bank for recovery; Tactic C-8. |
| ALP-19 | West bank of West Ulamnigiaq Channel north of CD3 pad | Pre-staged equipment and seasonally pre-deployed boom | Deflect oil toward bank for recovery; Tactic C-8. |
| ALP-20 | East bank of East Ulamnigiaq Channel northeast of CD3 pad | Seasonally pre-staged equipment | Deflect oil toward bank for recovery; Tactic C-8. |
| ALP-21 | East bank of east fork at the mouth of Sakoonang Channel. | Pre-staged equipment | Exclude oil from Harrison Bay; Tactic C-9. |
| NK-3 | Southwest area of Nanuk Lake | Seasonally pre-deployed boom | Exclude oil from Nanuk Lake; Tactic C-9. |

| NAME | LOCATION | EQUIPMENT | RESPONSE STRATEGY |
|---|---|---|---|
| NK-4 | East bank of Nigliq Channel north of Nigliq bridge pipeline crossing | Pre-staged equipment | Deflect oil toward bank for recovery; Tactic C-8. |
| CC-1 | East bank of Nigliagvik Channel north of Nigliagvik bridge pipeline crossing | Seasonally pre-deployed boom | Deflect oil toward bank for recovery; Tactic C-8. |
| CC-2 | West bank of Nigliq Channel north of Nigliq bridge pipeline crossing | Seasonally pre-staged equipment | Deflect oil toward bank for recovery; Tactic C-8. Exclusion booming; Tactic C-9. |
| CC-3 | East bank of abandoned channel L9341 north of L9341 Bridge pipeline crossing | Seasonally pre-staged equipment | Deflect oil toward bank for recovery; Tactic C-8. Exclusion booming; Tactic C-9. |
| SK-13 | Sakoonang Channel southeast of CD1 pad | Seasonally pre-deployed boom | Deflect oil toward bank for recovery; Tactic C-8. |
| SK-14 | Sakoonang Channel south of CD1 pad | Seasonally pre-deployed boom | Deflect oil toward bank for recovery; Tactic C-8. |
| SK-15 | Sakoonang Channel northeast of CD1 pad | Seasonally pre-deployed boom | Deflect oil toward bank for recovery; Tactic C-8. |
| CD5 | CD5 pad | Pre-staged equipment | Varies; deflect oil toward bank for recovery; Tactic C-8. |
| TIN-1* | North of Tinmiaqsiugvik River bridge and pipeline crossing | Seasonally pre-deployed boom | Deflect oil toward bank for recovery; Tactic C-8. |
| FC-1 | Approximately 3.5 miles downstream of Tinmiaqsiugvik River bridge; north of large lake | Pre-staged equipment | Varies; deflect oil toward bank for recovery; Tactic C-8. Exclusion booming; Tactic C-9. |
| CRC-1* | GMT1 road near Crea Creek bridge and pipeline crossing | Seasonally pre-staged equipment | Deflect oil toward bank for recovery; Tactic C-8. Exclusion booming; Tactic C-9. |
| GMT1 | GMT1 Pad | Pre-staged equipment | Varies; deflect oil toward bank for recovery; Tactic C-8. |

* locations and equipment are proposed to support GMT1 development starting summer 2019 and are subject to change.

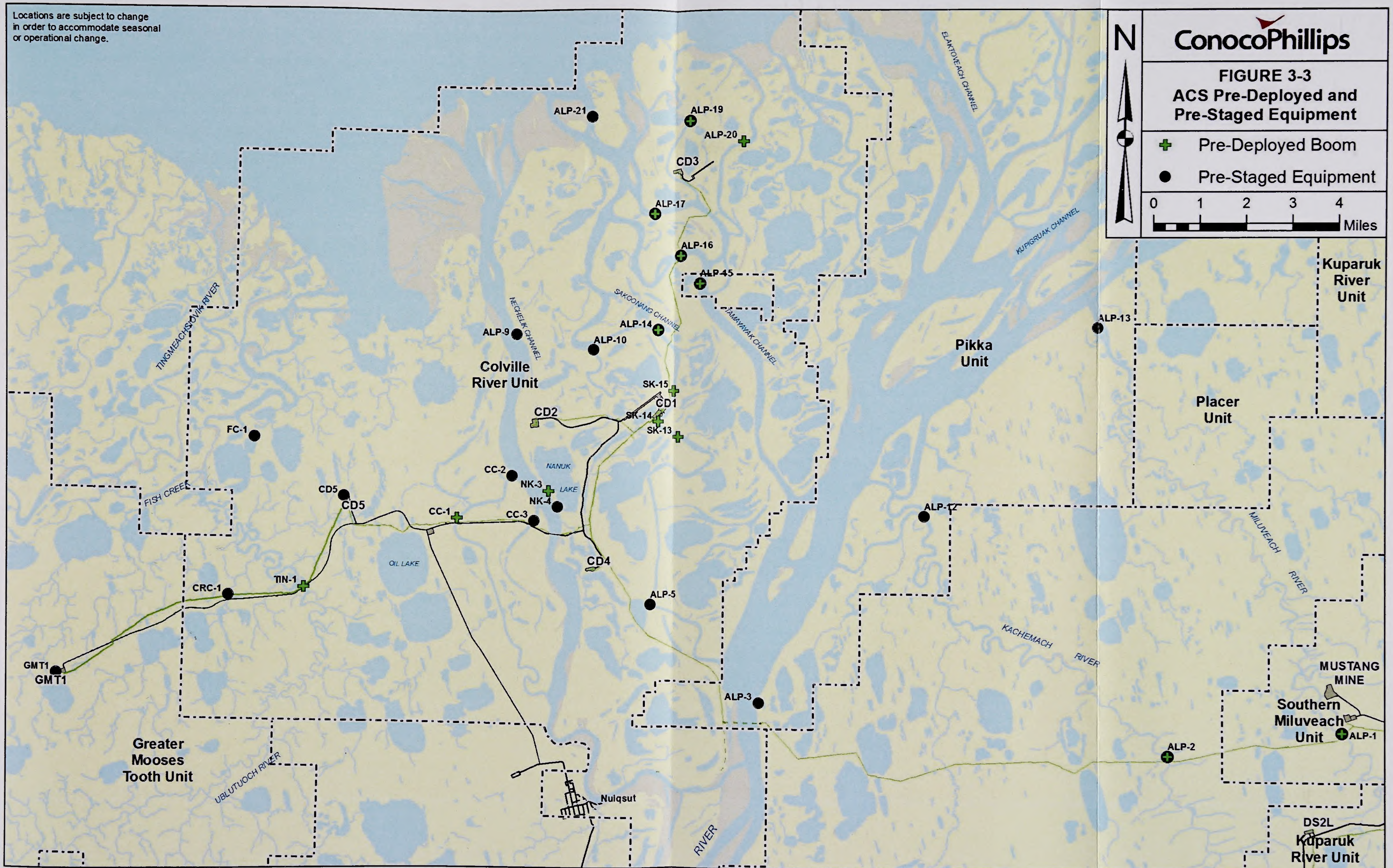
## 3.6.3 Maintenance and Inspection of Response Equipment

Response equipment is maintained in a condition for immediate use and rapid deployment. ACS performs routine inspection and maintenance of its response equipment. ACS inspections, tests, and maintenance follow ACS written standard operating procedures.

ACS is a registered State of Alaska Oil Spill Primary Response Action Contractor (PRAC), and maintains certification as a U.S. Coast Guard Oil Spill Removal Organization (OSRO). ACS PRAC and OSRO certification information is provided in ACS *Technical Manual*, Volume 1 Tactic A-5.

ACS has fulfilled the equipment maintenance and testing criteria required by these certifications.

BLANK PAGE


Locations are subject to change in order to accommodate seasonal or operational change.
ConocoPhillips
FIGURE 3-3
ACS Pre-Deployed and Pre-Staged Equipment
Pre-Deployed Boom
Pre-Staged Equipment
0 1 2 3 4 Miles
N
ALP-21
ALP-19
ALP-20
CD3
ALP-17
ALP-16
ALP-15
ALP-14
ALP-10
ALP-9
Colville River Unit
SK-15
CD1
SK-14
SK-13
CD2
FC-1
CC-2
NK-3
NK-4
CD5
CC-1
CC-3
CD4
TIN-1
CRC-1
ALP-5
GMT1
ALP-3
ALP-13
ALP-12
ALP-2
ALP-1
Pikka Unit
Placer Unit
Kuparuk River Unit
MUSTANG MINE
Southern Miluveach Unit
DS2L
Greater Mooses Tooth Unit
Nuiqsut
OIL LAKE
NANUK LAKE
FISH CREEK
UBLUTUOCH RIVER
KACHEMACH RIVER
MILUVEACH RIVER
KUPIGRUAK CHANNEL
ELAKTOVEACH CHANNEL
SAKOONANG CHANNEL
TAMAYAYAK CHANNEL
NECHELIK CHANNEL
TINGMEACHSIOVIK RIVER
RIVER

BLANK PAGE

## 3.7 NON MECHANICAL RESPONSE INFORMATION [18 AAC 75.425(e)(3)(G)]

Non-mechanical response is attempted only in situations where mechanical recovery cannot be accomplished without unacceptable environmental damage or unacceptable risk to personnel, or when mechanical recovery cannot be completed before the threat of further migration of contained oil is imminent. In situ burning will not be used as a substitute for mechanical recovery.

In situ burning equipment inventory and deployment is described in the ACS *Technical Manual* Tactics L-6 and B-2 through B-7, incorporated here by reference.

### 3.7.1 Environmental Consequences and Protection of Sensitive Areas

The environmental consequences of in situ burning will be assessed by monitoring the downwind trajectory of the smoke. A trial burn will indicate the path of the smoke. Monitoring the downwind position of the smoke plume will be accomplished by a ground- or air-based member of the IMT.

Appropriate measures, as required by the Unified Command, natural resource agencies, and public safety agencies, will be carried out to protect nearby human populations and environmentally sensitive areas. In situ burns will be limited to sites that are a minimum safe distance, generally several miles upwind of human populations. The safe distance will be plotted as outlined in the "In Situ Burning Guidelines for Alaska". The determination takes into account a trial burn, wind conditions, and size of the expected burn area. In addition, public notifications and warnings will be issued in cooperation with agency emergency staff.

In situ burns conducted according to the Unified Plan are not expected to harm environmentally sensitive areas and areas of public concern. Heat from in situ burning affects only the upper few centimeters of the water column in contact with the oil. Smoke has not been found harmful to wildlife populations. In situ burning smoke is reduced to concentrations that are safe to people by means of burning only at safe distances (see Table 3-8).

In situ burn operations receive constant visual monitoring of the smoke plume's behavior. The Burn Operations Team visually monitors the smoke plume. The federal and state On-Scene Coordinators may authorize a trial burn to confirm anticipated plume drift direction and dispersion distances downwind before authorizing the proposed burn. Burn operations may be stopped if the plume contacts or threatens to contact the ground in a populated area.

A step-by-step process in establishing safe distances for burning is fully presented in the "In Situ Burning Guidelines for Alaska; Section 1.7 provides information about permits and approval required for in situ burning.". The state and federal On-Scene Coordinators determine whether the burn lies at a safe distance from human populations. In situ burning is not authorized if it does not meet public health regulatory standards. The safe distance separating human populations from in situ oil burns is the downwind radius from the fire at which smoke particulate matter concentrations at the ground diminish to limits established by National Ambient Air Quality Standards. The safe distance guidelines are based on the predictions of a National Institute of Standards and Technology ALOFT-Flat Terrain computer model.

The safe distance meets the National Ambient Air Quality Standards for particulate matter over a one-hour time period and is also used as the indicator that human populations will not be exposed to unsafe levels of all other smoke components. Table 3-8 lists the general safe distances separating an in situ burn and downwind populated areas in flat terrain.

**TABLE 3-8: SAFE DISTANCES BETWEEN IN SITU BURNS AND DOWNWIND HUMAN POPULATIONS IN FLAT TERRAIN: LOCATION OF FIRE ZONES**

| LOCATION OF FIRE | GREEN ZONE | YELLOW ZONE | RED ZONE |
|---|---|---|---|
| Flat terrain on land | >3 miles | 1 to 3 miles | <1 mile |
| Water <3 miles from shore | | | |
| Water >3 miles from shore | >1 mile | Not applicable | <1 mile |

Burning at a green zone safe distance from the public is acceptable following public notification.

The "In Situ Burning Guidelines for Alaska" allow results of National Institute of Standards and Technology modeling to be used to authorize burning on the North Slope. The results show that for fires up to 10,000 square feet in area (about 100 feet in diameter, in all wind speeds modeled over land or water in typical winter and summer atmospheric conditions), the surface concentrations of particulate matter decline below the target concentration in less than 0.6 mile of the burn. Fifty-six scenarios in Cook Inlet and the North Slope were modeled using the ALOFT-Flat Terrain computer model, and the worst case predictions were used to develop the safe distances for those specific locations.

The Unified Plan aims to protect wildlife and habitat threatened by an oil spill by using in situ burning where mechanical methods become inadequate to contain and remove spilled oil. The ARRT's Science and Technology Committee further decided that in situ burning can reduce the threat to wildlife posed by untreated oil, and that this benefit outweighs the potential harm posed by in situ burning smoke and residue. The Committee also decided not to require the incident-specific identification of wildlife threatened by in situ burning based party on a report by Campbell et al. (1994) regarding the environmental trade-offs of in situ burning. It concluded that in offshore, nearshore, and estuarine environments, burning a crude oil spill poses less risk to wildlife than not burning. Burning greatly reduces the volume of oil and therefore, the probability that oil comes in contact with wildlife. Burning also eliminates the volatile/soluble fraction of the spill.

### 3.7.2 Operational Capability

ACS maintains specialized equipment to conduct in situ burning operations during all seasons and all ice conditions as described in Section 3.4.3. The extensive inventory of response equipment is specifically designed to support a large-scale burning operation. Section 3.4.3 describes the effectiveness of in situ burning in ice.

### 3.7.3 Effectiveness of In Situ Burning in Ice

The consensus of research on spill response in broken ice conditions is that in situ burning is an effective response technique with removal rates exceeding 85 percent in many situations (Shell et al. 1983, SL Ross 1983, SL Ross and DF Dickins 1987, Singsaas et al. 1994, SL Ross et al. 1998, DF Dickins et al. 2000, Sørstrøm et al. 2010).

### 3.7.4 Permits, Approvals, and Authorizations

Permits, approvals, and authorizations required to implement in situ burning are described in ACS Tactic B-1. Each response is different and as such, a specific time-line for obtaining permit approvals and authorizations is not defined. The tactic cannot be executed until all permits, approvals, and authorizations are in place. Tactic B-1 refers to Annex F of the Unified Plan which provides further detail on the use of the

in situ burning response options. ACS maintains emergency use permits that can be activated during a response (ACS Tactic A-3).

## 3.8 RESPONSE CONTRACTOR INFORMATION [18 AAC 75.425(e)(3)(H)]

Contact information for ACS:

| | |
|---|---|
| Phone | (907) 659-2405 (24-hour emergency number) |
| Fax | (907) 659-2616 |
| Mailing Address: | Pouch 340022 |
| | Prudhoe Bay, Alaska 99734-0022 |

COPA will activate ACS to provide the initial manpower and resources required to respond to a large or lengthy spill response. If additional resources are required, they will be accessed through contracts maintained by ACS. COPA's Statement of Contractual Terms and Response Action Contract signature page with ACS is presented as Figure 3-4 and Figure 3-5, respectively.

## FIGURE 3-4: ACS STATEMENT OF CONTRACTUAL TERMS

### STATEMENT OF CONTRACTUAL TERMS

AS REQUIRED UNDER AS46.04.30, AS 46.04.035, and 18 AAC 75.445(l) (1) in fulfillment of requirement for registration of primary response action contractors and for approval of an Oil Discharge Prevention and Contingency Plan

PLAN TITLE: Alpine ODPCP, Kuparuk ODPCP, and North Slope Exploration ODPCP

PLAN HOLDER: ConocoPhillips, Alaska Inc.

This statement is a certification to the Alaska Department of Environmental Conservation summarizing the contract between ConocoPhillips, Alaska, Inc. the oil discharge prevention and contingency plan holder (hereinafter "PLAN HOLDER"), and **Alaska Clean Seas**, the oil spill primary response action contractor or a holder of an approved oil discharge prevention and contingency plan under contract (hereinafter "CONTRACTOR"), executed on July 1, 2014, and the original of which is located at 3300 C Street, Suite 200, Anchorage, AK 99503, as evidence of the PLAN HOLDER's access to the containment, control and/or cleanup resources required under standards at AS 46.04.030 and 18 AAC 75.400 -- 18 AAC 75.495.

The PLAN HOLDER and the CONTRACTOR attest to the Department that the provisions of this written contract clearly obligate the CONTRACTOR TO:

(A) provide the response and equipment listed for the CONTRACTOR in the contingency plan;

(B) respond if a discharge occurs;

(C) notify the PLAN HOLDER immediately if the CONTRACTOR cannot carry out the response actions specified in this contract or the contingency plan;

(D) give written notice at least 30 days before terminating this contract with the PLAN HOLDER;

(E) respond to a Department-conducted discharge exercise required of the PLAN HOLDER; and

(F) continuously maintain in a state of readiness, in accordance with industry standards, the equipment and other spill response resources to be provided by the CONTRACTOR under the contingency plan.

Statement of Contractual Terms
Page 1 of 2

**STATEMENT OF CONTRACTUAL TERMS**

I hereby certify that, as representative of the PLAN HOLDER, I have the authority to legally bind the PLAN HOLDER in this matter. I am aware that false statements, representation, or certifications may be punishable as civil or criminal violations of law.

3/9/17

Signature Date

Lisa Bruner

Title: VP, NS Operations and Development

For: ConocoPhillips Alaska, Inc.

PLAN HOLDER

I hereby certify that, as representative of the CONTRACTOR, I have authority to legally bind the CONTRACTOR in this matter. I am aware that false statements, representation, or certifications may be punishable as civil or criminal violations of law.

March 8. 2017

Signature Date:

Title: C. Barkley Lloyd

President & General Manager

For: Alaska Clean Seas

CONTRACTOR

Statement of Contractual Terms

Page 2 of 2

## FIGURE 3-5: ACS-COPA MEMBER RESPONSE ACTION CONTRACT SIGNATURE PAGE

(G) **Survival.** Notwithstanding the termination of this RAC, the provisions of this RAC that, by their nature, shall survive any expiration or termination.

(H) **Amendment.** This RAC may be amended only in writing signed by all Parties

(I) **Entire Understanding.** The terms set forth in this RAC supersede all previous discussions, understandings and agreements between the Parties hereto with respect to the subject matter hereof, and are intended by the Parties as a final, complete and exclusive expression of the terms of their agreement and may not be contradicted, explained or supplemented by evidence of any prior agreement or any contemporaneous oral agreement.

(J) **Conflicts.** This RAC is to be interpreted in harmony with the ACS Bylaws. In the event of a conflict between the provisions of this RAC and the ACS Bylaws, the terms of the ACS Bylaws shall control.

**IN WITNESS WHEREOF**, the Parties have signed this RAC.

| **ACS**<br>**Alaska Clean Seas** | | **MEMBER**<br>**ConocoPhillips, Alaska Inc.** | |
|---|---|---|---|
| Signature: | C. Barkley Lloyd 2014.06.26 09:06:09 -08'00' | Signature | Nicholas G. Olds |
| Name: | C. Barkley Lloyd | Name: | Nicholas G. Olds |
| Title: | President and General Manager | Title | VP North Slope Ops & Development |
| Date: | June 26, 2014 | Date: | October 29, 2014 |

## 3.9 RESPONSE TRAINING PROGRAM [18 AAC 75.425(e)(3)(I)]

COPA, in conjunction with ACS, provides an extensive training program for employees and contractors who volunteer for the North Slope Spill Response Team (NSSRT). COPA also provides relevant ICS training for employees and contractors who volunteer for the IMT.

### 3.9.1 NSSRT Spill Response Training

The NSSRT consists of workers who volunteer as emergency spill response personnel. Each team member is required to have initial emergency response training and annual refresher training, which meets or exceeds the requirements HAZWOPER regulations, 29 CFR 1910.120(q). Qualified responders must have a minimum of 24-Hour HAZWOPER training and annual requirements for HAZWOPER refreshers, medical clearance (physical), and a valid respiratory fit test, in addition to required training within each individual labor category (see ACS Tactic A-4). The ACS Training Department tracks these requirements and distributes a monthly "Readiness Report" of responder status, which is generated from the ACS database. Alpine SRT members are trained as NSSRT members or are ACS employees. Alpine SRT members are trained according to the NSSRT training requirements described in ACS *Technical Manual* Tactic A-4; ACS employees may have additional training.

The NSSRT training program offers weekly classes at each field. These classes emphasize hands-on experience, field exercises, and team building drills. The courses are selected by the facility Lead ACS Technician in conjunction with field management, and use COPA, ACS, and external training consultants. Due to operational time constraints, many of the courses are divided by subject area and are taught in the two- or three-hour time frame of an NSSRT meeting. Training and attendance is documented and maintained by ACS. The yearly training schedule is also available at the facility and at ACS. Current NSSRT training schedules are posted on the ACS web site.

### 3.9.2 IMT Member Training

IMT member training includes an introduction to the ICS, ICS position specific training, tabletop exercises, and deployment drills. As new training needs are identified, they are developed and incorporated into the IMT training program. The COPA *Alaska Emergency Management Teams Procedure* delineates roles, responsibilities, and training requirements for COPA IMT members. IMT members are expected to complete initial training and annual training and drill events to maintain proficiency in their positions. The IMT receives training on the ODPCP through computer-based training module. Periodic announced and unannounced drills ensure IMT members understand their roles and responsibilities within the ICS and under the ODPCP.

### 3.9.3 Auxiliary Contract Response Team

ACS maintains third-party contracts to ensure North Slope Operators have the ability to provide personnel required to support a long-term response. The program consists of contracts and agreements with various spill response contractors and provides assurance that a host of trained and qualified responders are available to respond to oil spills on the North Slope.

### 3.9.4 Other Training

COPA employees and contract personnel involved in spill response are required to attend hydrogen sulfide training and may receive firefighting training. In addition, there may be specific departmental training requirements for Alpine facility operations.. Operators and facility personnel receive annual training on the

Emergency Action Plan, which covers procedures for reporting, notification, alarms, evacuation, and duties to perform during an emergency at Alpine facilities.

The Alpine fire team may be involved in a spill response due to threat of fire. The team is trained to National Fire Protection Agency standards that permit personnel to be certified as State of Alaska Firefighters at the I and II levels, certified as Driver/Operators of Fire Apparatus and as Certified Fire Officers. Training is conducted in order to ground people in the skills needed as well as providing practical opportunities to become proficient in the tasks needed to operate as a firefighter. Training records are held in an electronic data base for as long as the individual is an active member of the team.

Basic spill response and/or ICS training is provided to representatives of the local community that may be involved in a spill response, contingent upon availability and willingness of participants, along with COPA operational needs. North Slope Borough officials are typically involved in COPA-led response exercises and/or the annual Mutual Aid Drill, which are opportunities for spill response training.

### 3.9.5 Recordkeeping

Training records for COPA employees with duties under this response plan are maintained by the COPA HSE Department and/or human resources. Recordkeeping practices are conducted in accordance with Company policy and applicable retention periods. COPA employee records are maintained for the period of employment plus a minimum of five years. Records of COPA employees with assigned duties directly related to operation of DOT-regulated pipelines are maintained until the employee is no longer assigned those duties, plus five years. ACS maintains training records for NSSRT personnel, including COPA employees and contractors. The ACS Training Department maintains a database as a record of the courses taken by each employee and contractor. Records are kept for a minimum of five years or for the entire time the employee or contractor is assigned responsibilities under ACS programs. The database provides a description of the course and the date completed. Current training status of employees and contractors is available by contacting the ACS Training Department.

### 3.9.6 Spill Response Exercises

COPA conducts or participates in several types of spill response exercises every year, including QI and/or IMT notification, IMT tabletop, equipment deployment, and unannounced. Most exercises are conducted by COPA, some are conducted by regulatory agencies, while others are conducted by ACS or its member companies (e.g., Mutual Aid Drill [MAD]). In addition, actions taken during actual spill response incidents may fulfill exercise requirements.

COPA has adopted the National Preparedness for Response Exercise Program (PREP) Guidelines for preparation and implementation of COPA-led spill response exercises. The Guidelines specify 15 core components to implement in a response exercise program. The 15 components are:

**Organizational Design:**

- Notifications;
- Staff mobilization; and
- Ability to operate within the response management system described in the plan.

**Operational Response:**

- Source control;
- Assessment of discharge;
- Containment of discharge;
- Mitigation of discharge;
- Protection of economically and environmentally sensitive areas; and
- Disposal of recovered product.

**Response Support:**

- Communications;
- Transportation;
- Personnel support;
- Equipment maintenance and support;
- Procurement; and
- Documentation.

The COPA Crisis Management and Emergency Response Coordinator is responsible for scheduling, coordinating, and implementing COPA-led spill response exercises to ensure they meet NPREP requirements on an annual basis and within a triennial cycle. COPA -led exercises are self-evaluated and self-certified as meeting PREP guidelines. Supporting documentation from an exercise or drill, and in some cases an actual event, if actions taken will be used for PREP credit, is maintained for a minimum of five years. ACS leads equipment deployment exercises to meet PREP requirements.

The COPA response exercise program includes the following:

- Quarterly QI Notification Drills – ensure the QI is available on a 24-hour basis and can carry out assigned duties.
- Annual IMT Tabletop Exercises – ensure personnel are knowledgeable of ICS roles and responsibilities, and familiar with notification telephone numbers and procedures.
- Equipment Deployment Exercises – ensure response equipment is fully functional and ready to deploy, and provide hands-on training opportunity for NSSRT members. These exercises are managed by ACS.
- Triennial Exercise of the Response Plan – ensures all components of National PREP are exercised every three years; and
- Government-initiated unannounced exercises.

COPA may participate in the North Slope operator's annual MAD exercise. In addition to actively participating in the MAD, federal, state, and local agencies are involved in the development and evaluation of the drill. Equipment may be deployed at the MAD per PREP guidelines, and the MAD exercise may satisfy PREP requirements to exercise all aspects of the response plan at least every three years.

## 3.10 PROTECTION OF ENVIRONMENTALLY SENSITIVE AREAS [18 AAC 75.425(e)(3)(J)]

Priority protection sites, environmentally sensitive areas, and areas of public concern that may be impacted during a worst case discharge are described within the scenarios in Section 1.6.3, Response Scenarios and Strategies. Additional resources used to identify environmentally sensitive areas and areas of public concern include the ACS *Technical Manual*, Volume 2, Map Atlas; the North Slope Subarea Contingency Plan; and NOAA Environmental Sensitivity Index (ESI) Maps. Environmentally sensitive areas and areas of public concern include bird nesting areas, fish-bearing lakes and streams, marine and terrestrial mammal areas, cultural resource and historic sites, and Native allotments.

The ACS *Technical Manual*, Volume 2, Map Sheets 1 through 30 and 53 include specific information about priority protection sites and local environmental and cultural sensitivities for areas around Alpine facilities and pipelines. In addition, wildlife protection strategies are described in the ACS *Technical Manual,* Volume 1, Tactics W-1 through W-6. The ACS *Technical Manual* is available online at:
http://www.alaskacleanseas.org

The North Slope Subarea Contingency Plan is a sub-plan of the Unified Plan, Alaska's Area Contingency Plan. It includes specific information on biological and cultural resources on the North Slope for use during initial phases of a spill response. The Subarea Plan includes data on resource sensitivity, habitat types, threatened and endangered species, and has numerous wildlife maps and references to online resources to aid in protection of the environment during a spill response. The Subarea Plan is available online at:
http://dec.alaska.gov/spar/perp/plans/scp_ns.htm

NOAA ESI maps are another important resource for identifying environmentally sensitive areas within the Alpine facilities and pipelines operating area. ESI maps help identify locations vulnerable to oil spills, and can help establish protection priorities and identify cleanup strategies. North Slope ESI maps numbers ESI-7 and ESI-8 cover the Alpine area and are available online at:
http://response.restoration.noaa.gov/esi

The state of Alaska has established a "Prevention and Emergency Response Subarea Plans Maps" section to their online Alaska State Geo-Spatial Data Clearinghouse. It contains links to subarea plans and their related maps, ESI maps, and other mapping resources such as: nautical and oceanographic charts, land use and management maps, biologically sensitive areas maps, most environmentally sensitive areas maps, and geographic response strategies (GRS) maps. The online Alaska maps clearinghouse is available via the following link:
http://www.asgdc.state.ak.us/maps/cplans/subareas.html#northslope

Alpine is located in a remote, rural onshore area where the economic base is the oil and gas exploration and production industry, and the government sector. An oil spill from Alpine facilities or pipelines would not significantly impact an economically sensitive area; however there is potential to impact local subsistence areas and practices. Nuiqsut is located near the main channel of the Colville River, approximately 8 miles south of Alpine CD1 pad. The population measured in the 2015 consensus was 415 residents. Nuiqsut provides modern amenities such as governance, infrastructure, schools, and an airport. Residents maintain recreational and subsistence hunting and gathering resources within the Alpine area; these are an essential part of the culture and community and require protection. The proximity of Nuiqsut would require close monitoring of meteorological conditions and communication and consultation with Nuiqsut representatives (through Unified Command) concerning how best to mitigate potential health effects on the community resulting from a major spill response. If historic, prehistoric, or archaeological sites or materials are

uncovered during spill recovery operations, the site is protected to prevent oiling and limit access, and ADNR Office of History and Archaeology is notified.

### 3.10.1 Persistence and Toxicity Effects of Products in the Environment [18 AAC 75.425(e)(3)(J)(ii)]

**Crude Oil**

Sweet crude oil is amber to black colored liquid. It typically has a sulfurous odor similar to rotten eggs. Crude oil is stable under normal ambient and anticipated conditions of storage and handling. It is extremely flammable as a liquid and vapor. The vapor can cause flash fire. Crude oil exhibited an increase incidence of skin tumors with a chronic application to mouse skin. There is limited evidence of carcinogenicity in animals, and crude oil is not classifiable as to its carcinogenicity in humans. It has not been listed as a carcinogen by the National Toxicology Program (NTP) or by OSHA. Dermal exposure to crude oil during pregnancy resulted in limited evidence of developmental toxicity in laboratory animals. Decreased fetal weight and increased resorptions were noted at maternally toxic doses in laboratory animals. No significant effects on offspring growth or other developmental landmarks were observed postnatally.

**Ultra Low Sulfur Diesel Oil**

Ultra low sulfur diesel oil is a liquid that is amber to various colors. It may be dyed red. It is combustible as a liquid and vapor. It is harmful if swallowed. It is harmful or fatal if the liquid is aspirated into the lungs. It causes skin irritation. It may cause respiratory tract irritation. Inhalation causes headache, dizziness, drowsiness, and nausea, and may lead to unconsciousness. It is stable under recommended storage and handling conditions.

No component of this product at levels greater than 0.1% is identified as a carcinogen by the American Conference of Governmental Industrial Hygienists or the International Agency for Research on Cancer (IARC.) No component of this product present at levels greater than 0.1% is identified as a carcinogen by the NTP or OSHA. Diesel is toxic to aquatic organisms. It may cause long-term adverse effects in the aquatic environment. Spillages may penetrate the soil causing groundwater contamination. It is not expected to bioaccumulate through food chains in the environment. Spills may form a film on water surfaces causing physical damage to organisms. Oxygen transfer could also be impaired.

**No. 1 Diesel**

No. 1 Diesel is a crystal-clear liquid with a kerosene-like odor. It is an extremely flammable liquid and vapor. The vapor may cause flash fire or explosion. It may be harmful or fatal if swallowed and may cause lung damage. It contains chemicals that are both human and animal carcinogens. It is toxic to aquatic organisms. Regarding persistence and degradability, it is not readily biodegradable. It may bioaccumulate in aquatic organisms. Regarding mobility in environmental media, it may partition into air, soil, and water.

**Lube Oil**

Lube oil ranges from a clear and bright to amber liquid in color with a petroleum odor. It is stable under anticipated normal handling and storage conditions. Acute aspirations of large amounts of material may produce serious aspiration pneumonia and can cause irritation and redness to eyes and skin. All of the oils meet the IP-346 criteria of less than 3 percent polyaromatic hydrocarbons and are not considered carcinogens by IARC, NTP, or OSHA.

Extended exposure to high temperature may cause it to decompose. Volatilization is not significant after release of lubricating oil basestocks to the environment due to the very low vapor pressure of the hydrocarbon constituents. In water, lubricating oil basestocks will float and spread at a rate that is viscosity dependent. Water solubility is very low and dispersion occurs mainly from water movement with adsorption by sediment. In soil, lubricating oil basestocks show little mobility and adsorption is the predominant physical process.

**Emulsion Breaker**

Emulsion Breaker is a clear, yellow to amber color liquid with a hydrocarbon odor. It is flammable and should not be exposed to heat, sparks, and flames. It is harmful if inhaled, swallowed, or absorption through skin and could cause irreversible effects. It may cause eye irritation. Emulsion Breaker containing methanol could cause blindness. Emulsion Breaker containing naphthalene is listed as reasonably anticipated to be carcinogenic by NTP, and listed as IARC Group 2B, possibly carcinogenic to humans. It is toxic to aquatic organisms and may cause long-term adverse effects in the aquatic environment.

**Anti-Foam**

Anti-foam is a colorless to pink liquid with a hydrocarbon odor. The liquid and vapor is flammable and should not be exposed to heat, sparks, flames, or other ignition sources. It is harmful if swallowed. It is harmful or fatal if the liquid is aspirated into the lungs. It causes skin irritation. It may cause respiratory tract irritation. Inhalation causes headache, dizziness, drowsiness, and nausea, and may lead to unconsciousness. It is suspected of causing cancer and is not listed as a carcinogen by IARC, NTP or OSHA.

Hydrocarbons in Anti-foam are not readily biodegradable but are regarded as inherently biodegradable since their hydrocarbon components can be degraded by microorganisms. On release to water, hydrocarbons will float on the surface and since they are sparingly soluble, the only significant loss is volatilization to air. It is possible that some of the hydrocarbons will be adsorbed on sediment. It is toxic to aquatic organisms and may cause long-term adverse effects in the aquatic environment. Biodegradation in water is a minor loss process and are photodegraded in air.

**Corrosion Inhibitor**

Corrosion Inhibitor is a brown liquid that is corrosive and highly flammable. Harmful by inhalation and ingestion with possible risk of irreversible effects. It may give off gas, vapor or dust that is very irritating or corrosive to the respiratory system and may cause burns to mouth, throat and stomach if ingested. It is corrosive and can cause burns to the skin and eyes. The naphthalene component is listed as reasonably anticipated to be carcinogenic by NTP, and listed as IARC Group 2B, possibly carcinogenic to humans. It is toxic to aquatic organisms and may cause long-term adverse effects in the aquatic environment.

### 3.10.2 Prediction of Discharge Movement

Flow from a release is from either a pipeline or a gravel pad to nearby tundra and ponds in summer and to frozen, snow-covered tundra and ponds in winter. See ACS Technical Manual, Volume 1 Tactics T-6 and T-7 for discussion of oil-retention rates of snow and for blowout aerial oil plume distribution, as well as Volume 2 Map Sheets 1 through 30 and 53 for information on likely surface drainage direction of flow.

## 3.10.3 Information on Probable Points of Contact

Spilled oil will reach tundra and ponds in summer and frozen, snow- and ice-covered surfaces in winter. Oil trajectories are not expected to affect open water of Harrison Bay; but may impact environmentally sensitive areas or areas of public concern including migratory bird nesting locations and local subsistence areas.

## 3.11 ADDITIONAL INFORMATION [18 AAC 75.425(e)(3)(K)]

Under 18 AAC 75.066(b)(2), a shop-fabricated oil storage tank built after December 31, 2008 to a design equivalent to industry standards specified by 18 AAC 75.066(b)(1) must be approved by ADEC. Letters of approval are provided in Appendix E; content is as follows:

- January 21, 2016. Tank Design Approval #2016-01.
- October 27, 2014. Tank Design Approval #2014-01.
- February 28, 2013. Approval of Oil Storage Tank Construction Standards
- February 9, 2005. Waiver of Oil Storage Tank Construction Standards.
- February 26, 2003. Waiver [approval] of Oil Storage Tank Construction Standards.
- February 14, 2003. Waiver [approval] of Oil Storage Tank Construction Standards.

## 3.12 BIBLIOGRAPHY [18 AAC 75.425(e)(3)(L)]


Alaska Clean Seas (ACS). (latest version). ACS Technical Manual, Volume 1, Tactics Descriptions; Volume 2, Map Atlas, www.alaskacleanseas.org .

Alaska Regional Response Team (ARRT). (latest version). The Alaska Federal/State Preparedness Plan for Response to Oil & Hazardous Substance Discharges/Releases (Unified Plan). http://dec.alaska.gov/spar/perp/plans/uc.htm

Alaska Regional Response Team (ARRT), (latest version). Alaska Federal/State Preparedness Plan for Response to Oil & Hazardous Substance Discharges/Releases (Unified Plan), Volume II, Change 2, North Slope Subarea Contingency Plan.

Alaska State Geo-Spatial Data Clearinghouse. Prevention and Emergency Response Subarea Plan Maps, North Slope. Environmental Sensitivity Index Maps. http://www.asgdc.state.ak.us/maps/cplans/subareas.html#northslope .

Atwater, S.G. 1991. 1990 Endicott Environmental Monitoring Program Final Report: Ice Break-up and Freeze-up. Prepared by SAIC for the U.S. Army Corps of Engineers, Anchorage, Alaska.

Bech, C., P. Sveum, and I. Buist. 1993. The Effect of Wind, Ice and Waves on the In Situ Burning of Emulsions and Aged Oils. Proceedings of the Sixteenth Arctic and Marine Oilspill Program Technical Seminar, Calgary, AB. pp. 735-748.

Bronson, M., Thompson, E., McAdams F., and J. McHale. 2002. Ice Effects on Barge-based Oil Spill Response Systems in the Alaskan Beaufort Sea. Proceedings 25th Arctic and Marine Oilspill Program Technical Seminar (AMOP), Calgary, pp. 1253-1268.

Brown, H.M. and R.H. Goodman. 1986. In Situ Burning of Oil in Experimental Ice Leads. Environmental Studies Revolving Funds Report 064. National Energy Board, Calgary.

Buist, I.A. and D. F. Dickins. 1987. Experimental Spills of Crude Oil in Pack Ice. Proceedings of the 1987 Oil Spill Conference, April 6-9, Baltimore, Maryland. American Petroleum Institute, Washington, D.C., pp.373-382.

Bureau of Land Management (BLM). 2004. Alpine Satellite Development Plan Final Environmental Impact Statement. U.S. Department of Interior, BLM Alaska State Office, Anchorage, Alaska.

Campbell, T.E., Taylor, E. and D. Aurand. 1994. Ecological Risks Associated with Burning as a Spill Countermeasure in a Marine Environment. Proceedings of the 17th AMOP Technical Seminar, June 8-10, Vancouver, British Columbia, pp. 707-716.

Coastal Frontiers. 2001. Spring Breakup Equipment Access Test Program (Draft and Final), prepared for BP Exploration (Alaska), Inc., Anchorage, Alaska.

ConocoPhillips. 2005. NPR-A Oil Spill Response Strategy Study. Prepared by Polaris Applied Sciences, Inc. Unpublished study. Anchorage, Alaska. 121 pages.

Department of Transportation, U.S. Coast Guard, Research and Special Programs Administration, Environmental Protection Agency, Department of the Interior Minerals Management Service. (latest version). National Preparedness for Response Exercise Program (PREP) Guidelines.

DF Dickins Associates Ltd., Vaudrey & Associates, Inc., and SL Ross Environmental Research Limited. 2000. *Oil Spills in Ice Discussion Paper.* Prepared for Alaska Clean Seas, Prudhoe Bay, Alaska.

Dickins, D.F. and K. Vaudrey. 2000. Typical Environmental Conditions During Freeze-Up in Nearshore Alaskan Beaufort Sea. Prepared for Alaska Clean Seas.

Guénette, C.C. and R. Wighus, 1996. In Situ Burning of Crude Oil and Emulsions in Broken Ice. Proceedings of the 19th MOP Technical Seminar. Calgary, AB. pp. 895-906.

Gavin, A. 1976. Wildlife of the North Slope. The Islands of Offshore Prudhoe Bay: The Snow Geese of Howe Island; The Seventh Year of Study. Atlantic Richfield Company. pp. 71.

Morrow, J.E. 1980. The Freshwater Fishes of Alaska. Alaska Northwest Publishing Co., Anchorage.

Norton, D.W., I.W. Ailes, and J.A. Curatolo. 1975. Ecological relationships of the island tundra avifauna near Prudhoe Bay, Alaska. J. Brown (ed.). Ecological Investigations of the Tundra Biome in the Prudhoe Bay Region, Alaska. Biological Papers, University of Alaska. Special Report No. 2. pp. 125-133.

Parametrix, Inc. 1997. Alpine Development Project. Environmental Evaluation Document. September.

Polaris Applied Sciences, Inc. September 2003 (update). Oil Spill Strategy and Response Studies for the Channels of the Colville River Delta Region, Alaska. Prepared for Phillips Alaska, Inc.

Ray, S. and J.W. Aldrich. 1996. Part 4: Flood Magnitude and Frequency. pp. 35-40. In: M.T. Jorgenson, J.W. Aldrich, S.R. Ray, E.R. Pullman, Y. Shur, M.D. Smith, A. A. Stickney, and H.J. Walker. 1996. Geomorphology and Hydrology of the Colville River Delta, Alaska, 1995. Volume 1. Unpublished fourth annual report by ABR, Inc., Shannon and Wilson, Inc., and Louisiana State University to PAI Alaska, Inc., and Kuukpik Unit Owners, Anchorage, Alaska.

Scandpower A/S, Report No. 27.83.01/R1. 2001. "Blowout Frequency Assessment of Northstar." July.

Shell Oil Company, Sohio Alaska Petroleum Company, Exxon Company, U.S.A., Amoco Production Company. 1983. Oil Spill Response in the Arctic – Part 2: Field Demonstrations in Broken Ice., Shell Oil Company, Sohio Alaska Petroleum Company, Exxon Company, U.S.A., Amoco Production Company. Anchorage, Alaska.

Singsaas, I., P. Brandvik, P. Daling, M. Reed and A. Lewis. 1994. Fate and Behavior of Oils Spilled in the Presence of Ice – a Comparison of the Results from Recent Laboratory, Mesoscale Flume and Field Tests. Proceedings of the 17th AMOP Technical Seminar, June 8-10, Vancouver, British Columbia, pp. 355-370.

SL Ross Environmental Research Ltd., DF Dickins Associates Ltd., and Alaska Clean Seas. 2003. Tests to Determine the Limits of In Situ Burning of Thin Oil Slicks in Broken Ice. Report prepared for the U.S. Minerals Management Service and ExxonMobil Upstream Research.

SL Ross Environmental Research Ltd., D.F. Dickins and Associates Ltd. and Vaudrey and Associates, Inc. 1998. Evaluation of Cleanup Capabilities for Large Blowout Spills in the Alaskan Beaufort Sea During Periods of Broken Ice. April 23.

SL Ross Environmental Research Ltd. and DF Dickins Associates Ltd. 1987. Field Research Spills to Investigate the Physical and Chemical Fate of Oil in Pack Ice. Environmental Studies Revolving Funds Report No. 062. 95 pages.

SL Ross Environmental Research Ltd. 1983. Evaluation of Industry's Oil Spill Countermeasures Capability in Broken Ice Conditions in the Alaskan Beaufort Sea. Prepared for the Alaska Department of Environmental Conservation, Anchorage, Alaska.

Smith, N.K. and A. Diaz. 1987. In-Place Burning of Crude Oils in Broken Ice. Proceedings of the 1987 Oil Spill Conference, April 6-9, Baltimore, Maryland. American Petroleum Institute, Washington, D.C., pp. 383-387.

Sørstrøm, S.E., P.J. Brandvik, I. Buist, P. Daling, D. Dickins, L. Faksness, S. Potter, J.F. Rasmussen and I. Singsaas. 2010. Oil in Ice – Joint Industry Program on Oil Spill Contingency for Arctic and Ice Covered Waters, Summary Report.

Steinhauer, M.S., and P.D. Boehm. 1992. The composition and distribution of saturated and aromatic hydrocarbons in nearshore sediments, river sediments, and coastal peat of the Alaskan Beaufort Sea: Implications for detecting anthropogenic hydrocarbon inputs. Marine Environmental Research. 33:223-253.

U.S. Geological Survey. 1977. Water Resources Data for Alaska, Water Year 1976. Water-Data Report AK-76-1. pp. 401.

Vaudrey & Associates, Inc. 1998 Memorandum. Broken ice periods for selected production sites along the Alaskan Beaufort Coast. June 27.

# PART 4 BEST AVAILABLE TECHNOLOGY [18 AAC 75.425(e)(4)]

Part 4 discusses the best available technology (BAT) requirements contained in 18 AAC 75.425(e)(4)(A), (B), and (C) and addresses technologies not subject to response planning or performance standards in 18 AAC 75.445(k)(1) and (2). The discussion of each technology complies with the requirement to analyze applicable technologies and to provide justification that the technology is the best available.

## 4.1 COMMUNICATIONS [18 AAC 75.425(e)(4)(A)(i)]

The communications system for use in a spill response at Alpine is described in the ACS *Technical Manual*, Volume 1, Tactic L-11A, and is incorporated here by reference.

## 4.2 SOURCE CONTROL [18 AAC 75.425(e)(4)(A)(i)]

BAT analysis of source control for a well blowout, pipeline leak, and tank overflow is provided. COPA will use the services of professional well control specialists if well control is not regained by conventional mechanical means or natural occurrences.

### 4.2.1 Well Source Control

This BAT analysis reviews the techniques and methods to control a "deep" well blowout that has the potential to release liquid hydrocarbons at the surface. Inherent to this analysis are the assumptions that all primary and secondary levels of well control have failed and that all dynamic and mechanical attempts to regain primary or secondary well control have been ineffective.

Once an incident has escalated to a blowout incident of the magnitude described in Section 1.6, the two methods of well control are well capping and relief well drilling. COPA concludes well capping constitutes BAT for source control of a well blowout. Table 4-1 summarizes well capping as BAT for a well blowout. The rationale for acceptance of well capping as BAT is provided in the following discussion.

**Well Capping**

Well capping techniques have been developed and have proven to be efficient and effective in regaining control of damaged wells and in reducing associated environmental impacts. Well capping techniques and procedures have been developed and implemented by professional well control specialist companies throughout the world. COPA has the ability to mobilize specialized well control personnel and equipment to a North Slope location within 24 to 48 hours of notification.

Well capping is both compatible and feasible with all drilling operations because the technology is applied at the surface. There are no sensitivities to well types (extended reach drilling [ERD], horizontal, etc.) or location (remote, island, etc.). Well capping techniques have been applied both to land-based and offshore locations, and historically have been proven successful in regaining well control in shorter durations. Well capping techniques are preferred over the more time-intensive alternative of drilling a relief well. Blowouts are typically controlled with more conventional surface control or dynamic kill methods (blowout preventer [BOP] equipment, weighted drilling muds, or cement placement in the well) before well capping is attempted

or required; drilling relief wells is often a last resort when surface control or kill methods fail and well capping is not feasible.

The U.S. Bureau of Ocean Energy Management and SINTEF Civil and Environmental Engineering (Norway) data indicate well capping technologies provide the shortest duration and most effective option for regaining well control and minimizing environmental impacts. This is shown by the consistent application of well capping in response to well control events and also by the associated shorter duration to successfully regain well control using well capping, as compared to relief well drilling.

Other than the initial cost of the well control equipment currently stationed on the North Slope, maintaining an open contract with Boots & Coots is a minimal annual cost. Any additional services required during an actual response would be provided at previously agreed-to rates.

Well control events where well capping would not be the preferred response involve events in which the potential to release liquid hydrocarbons to the surface is highly unlikely (e.g., shallow gas, compromised surface casing or surface casing cement jobs, broaching or reasonable concern of broaching, inaccessible wellhead and/or casing).

**Relief Well Drilling**

The lead time involved in relocating a rig to a surface location and drilling a relief well necessitates early planning, which may be initiated concurrently with the implementation of surface control methods. If surface control methods fail, COPA relief well plans are fully implemented. COPA's decisions are made by management in accordance with procedures contained in the incident-specific relief well plan. It should be recognized that a relief well is generally considered as a last resort to regain control of a blowout. It is far more common to kill the well with surface kill techniques or for the well to cease flowing due to depletion or the formation of a natural bridge in the wellbore.

Relief well drilling technology is compatible with North Slope drilling operations, although it may be sensitive to both the well location and well type. Multiple drilling rigs that are capable of drilling a relief well are under contract on the North Slope. Downhole and surface equipment (e.g., tubulars, wellheads, etc.) to support relief well drilling operations are also available.

Relief well drilling has been attempted only once as a mitigation measure to control a blowout on the North Slope. This was the ARCO Cirque gas well blowout in 1992, where well control was regained by a combination of surface control techniques and an assist from natural bridging before the relief well reached total depth.

Relief well drilling is similar to current methods used to drill and complete North Slope wells today, and advances in directional drilling technology that allow for more precise wellbore placement increase likelihood of success of a relief well. However, relief well attempts are thus more sensitive to blowout well location and/or blowout well type. For extended reach wells, or remote locations with limited access, relief well drilling is both logistically challenging and time consuming, thereby adding an undesired increase to the overall environmental impact (volume spilled) from the blowout.

### 4.2.2 Pipeline Source Control

The pipeline source control procedures required by 18 AAC 75.425(e)(1)(F)(i) involve the placement of automatic shutdown valves (i.e., emergency shutdown [ESD] valves) at each terminus of the pipelines to

stop the flow of oil or product through the pipelines. Pipeline source control is also discussed in Section 1.6 scenarios.

**Crude Oil Transmission Pipeline**

The Alpine sales crude oil transmission pipeline is equipped with automated leak detection systems that alarm if a leak is detected, which would activate ESD action from the control room. In addition, the crude oil transmission pipeline includes vertical loops in seven locations – one on each side of the Colville River, two on opposite sides of the Kachemach River, two on opposite sides of the Miluveach River, and one between the Colville and Kachemach rivers. The vertical loops isolate oil within the pipeline to prevent total down-drain of the pipeline and decrease the potential amount spilled.

Valve isolation is an option compared to the pipeline profile changes, or vertical loops, shown in Table 4-2. Due to the remoteness of the Alpine crude oil transmission pipeline, use of vertical loops is considerably more effective in minimizing spill volumes during spill events. Moreover, the additional possibility of oil leakage at the mechanical connections of the valves, traditionally an area of concern and maintenance, is eliminated. Valves are needed on each terminus of the pipeline to keep any oil from entering or exiting in the event the pipeline needs to be isolated. The Alpine crude oil transmission pipeline Spill Isolation Strategy is presented as Appendix B.

Vertical loops are also analyzed, along with two technology options for the valves: automatic ball valves and automatic gate valves (Table 4-2). Both valve options, when installed in new condition, are similar in terms of availability, transferability, cost, compatibility, and feasibility. In terms of effectiveness, ball valves typically have slightly faster closure times than gate valves. For the Alpine crude oil transmission pipeline, automatic ball valves (block and bleed type) are used in combination with vertical loops. As required by 18 AAC 75.055(b), the flow of oil or product/gas can be completely stopped by these loops and valves within one hour after a discharge has been detected. The valve closure time for these types of valves is on the order of 30 seconds.

## 4.2.3 Tank Source Control

Source control procedures for purposes of this BAT analysis relate to the fill procedures and inlet valves controlling flow to regulated oil storage tanks identified in Appendix D, Table D-1. BAT analysis for tank source control is discussed in Table 4-3.

The tanks listed below are fitted with truck fill connections only. The tanks are:

- Lube oil tank,
- Completions fluid storage tanks, and
- Brine storage tanks.

Tank fill connections are grouped together on the east side of the Alpine Central Processing Facility tank farm. An impound basin will be provided under the truck loading/unloading area to ensure any minor discharges that might take place during filling operations are contained. Filling operations are closely supervised to ensure fill procedures are followed. Inlet valves on these truck fill connections are one-quarter-turn ball valves that must be operated manually.

Manual intervention is effective in source control because operators are required to remain at or near the tanks during loading and unloading operations, and because secondary containment and high-level audible and visual alarms are provided for these tanks.

The primary source of supply for the diesel fuel tank is the 2-inch-diameter diesel pipeline from Kuparuk. Filling of the tank from the pipeline will be an unmanned operation. The 2-inch-diameter diesel pipeline is fitted with an automated fail safe one-quarter-turn ball valve mounted close to the tank inlet that closes on detection of a high-level condition in the tank. The diesel tank is also fitted with a local truck fill connection so the tank can be used at times when the pipeline supply may be unavailable. Truck filling operations are closely supervised in the same manner as the three tanks discussed above. The truck fill connection on the diesel tank is fitted with a one-quarter-turn ball valve that must be operated manually. The truck fill connection is also fitted with a check valve to prevent back flow from the tank. The combination of valves is considered BAT for the service type.

The slop tank is an integral component of the oil treating process at Alpine and is the collection point for a number of oil-containing streams that may be released from the Alpine processing facilities. The contents of the slop tank are automatically pumped back into the inlet separator. Potential major sources of discharge to the slop tank are fitted with automated ball or flow control valves that close automatically by the distributed control system in the event of a first-stage, high-level condition in the slop tank. If the liquid level in the tank continues to increase despite the closure of these valves, it eventually reaches the set point for the second high-level transmitter. Should this second-stage, high-level condition be detected, the process control system initiates ESD of the entire process plant. Remedial action then must be initiated by operations staff before the plant can be restarted. The combination of valves and tie-in with the process plant ESD is considered BAT for the tank service type.

## TABLE 4-1: BEST AVAILABLE TECHNOLOGY ANALYSIS WELL BLOWOUT SOURCE CONTROL

| BAT EVALUATION CRITERIA | CURRENT METHOD: WELL CAPPING | ALTERNATE METHOD: RELIEF WELL DRILLING |
|---|---|---|
| **AVAILABILITY:**<br>Whether technology is best in use in other similar situations or is available for use by applicant | Well capping is in use globally. Fit-for-purpose well capping and well control equipment is located on the North Slope. Additional equipment can be on location within 24-48 hours. | Relief well drilling equipment (e.g., rigs, downhole tools, etc.) is available. |
| **TRANSFERABILITY:**<br>Whether each technology is transferable to applicant's operations | Equipment is currently available on the North Slope or on retainer via well control services contract. | Multiple drilling rigs are currently under contract on the North Slope. |
| **EFFECTIVENESS:**<br>Whether there is a reasonable expectation each technology will provide increased spill prevention or other environmental benefits | Numerous global companies provide successful applications of well capping. After natural bridging and conventional methods (e.g., BOP, mud, cementing, equipment repairs), well capping is the most frequent blowout control measure. Application of well capping provides the best opportunity for minimizing pollution impacts. | Rare, successful application of relief well drilling has been documented by industry. Industry data suggest a very small percentage of blowouts are successfully controlled with this technique. Relief well drilling, as compared to well control from dynamic and mechanical methods, is the longest pollution mitigation measure possible.<br>Relief wells may be the preferred response method in some well control events (e.g., shallow gas, compromised surface casing or surface casing cementing, broaching, etc.), but these events are unlikely to result in the release of liquid hydrocarbons. |
| **COST:**<br>The cost to the applicant of achieving BAT, including consideration of that cost relative to the remaining years of service of the technology in use by the applicant | Fit-for-purpose equipment is already owned or under long-term contract. Well capping requires the maintenance of open-end contracts with trained specialists to implement well control and capping operations. | Time and cost of permitting, location construction, well planning, and executing relief wells is estimated at 2-3 times the cost of well capping, excluding any lost production. |
| **AGE AND CONDITION:**<br>The age and condition of technology in use by the applicant | Well capping technology has improved since its application during the Iraq-Kuwait conflict in the early 1990s. Firefighting equipment is in place on the North Slope. | Relief well drilling technology is similar to current methods used to drill/complete North Slope wells. This technology is potentially sensitive to blowout well types (e.g., ERD). |
| **COMPATIBILITY:**<br>Whether each technology is compatible with existing operations and technologies in use by the applicant | Technology is compatible and applied at surface (no sensitivity to well type). | Technology is compatible, though potentially sensitive to blowout well types (e.g., ERD, remote locations, etc.). Survey uncertainty on high departure wells may result in problems intersecting target wellbore. |
| **FEASIBILITY:**<br>The practical feasibility of each technology in terms of engineering and other operational aspects | Method is feasible with all drilling operations. Applied at surface – no sensitivities to well type (e.g., ERD, remote locations, etc.). Prior proven success in offshore environments. Demonstrated success in historical well control efforts. | Method feasibility is contingent on geographical access near area of blowout. Lack of year-round access to some locations (e.g., offshore) limits application. There is little evidence of successful application of relief well drilling as the primary mitigation measure of control.<br>Relief wells may be the preferred response method in some well control events (e.g., shallow gas, compromised surf casing or surf casing cementing, broaching, etc.), but these events are unlikely to result in the release of liquid hydrocarbons. |

## TABLE 4-1 (CONTINUED): BEST AVAILABLE TECHNOLOGY ANALYSIS WELL BLOWOUT SOURCE CONTROL

| BAT EVALUATION CRITERIA | CURRENT METHOD: WELL CAPPING | ALTERNATE METHOD: RELIEF WELL DRILLING |
|---|---|---|
| **ENVIRONMENTAL IMPACTS:**<br>Whether other environmental impacts of each technology, such as air, land, water pollution, and energy requirements, offset any anticipated environmental benefits | Technology provides the best-proven opportunity to quickly reduce environmental impacts. Estimated duration of 18-30 days is significantly less than conventional alternative technologies. | Technology provides additional exposure and environmental risks during application (e.g., additional well control problems). Technology application may be seasonally limited, leading to durations of 60-180 days. Relief wells may require additional gravel placement and mobilization or demobilization pressures on the local environment. Drilling a relief well is accompanied by the additional risk of a second well control event. |

## TABLE 4-2: BEST AVAILABLE TECHNOLOGY ANALYSIS CRUDE OIL TRANSMISSION PIPELINE SOURCE CONTROL

| BAT EVALUATION CRITERIA | CURRENT METHOD: AUTOMATIC ISOLATION BALL VALVES AND VERTICAL LOOPS TO ELIMINATE DRAIN BACK | ALTERNATE METHOD: ADDITIONAL AUTOMATIC SHUTDOWN BALL VALVES | ALTERNATE METHOD: MANUAL BLOCK VALVES | ALTERNATE METHOD: REPLACEMENT OF AUTOMATIC SHUTDOWN BALL VALVES WITH GATE VALVES |
|---|---|---|---|---|
| **AVAILABILITY:** Whether technology is best in use in other similar situations or is available for use by applicant | The Alpine crude oil transmission pipeline has two automatic isolation valves at each terminus and seven vertical loops along its length. | Existing shutdown valves could be added to the system, and/or could replace the vertical loops. | Proposed valves and vertical loops could be replaced with manual block valves. | Gate valves could replace the ball valves and the vertical loops. |
| **TRANSFERABILITY:** Whether each technology is transferable to applicant's operations | Currently installed. | Method is transferable. | Method is transferable. | Method is transferable. |
| **EFFECTIVENESS:** Whether there is a reasonable expectation each technology will provide increased spill prevention or other environmental benefits | Automatic ball valves at each pipeline terminus, with vertical loops along its length, are effective in minimizing spill volumes during spill events. Vertical loops form a terrace structure that significantly limits the amount of oil spilled due to drain-down effects. Moreover, the additional possibility of oil leakage at the mechanical connections of the valves, traditionally an area of concern and maintenance, is eliminated. Because the area between valves is roadless, the risk of undetected valve leakage is reduced. | Automatic shutdown valves in place of vertical loops would provide similar containment results. However, the additional possibility of oil leakage at the mechanical connections of the valves, traditionally an area of concern and maintenance, would be added to the project in a roadless area. The potential for spills is increased because a valve/actuator could fail to close, potentially causing a fluid hammer condition that could overpressure the line. Additionally, failure to close, while not adding to the risk of a spill, could allow more oil to spill. | Increased shutdown time associated with manual block valves in a roadless area would be significant. Compared to manual isolation block valves, vertical loops decrease the projected spill volume by 63% at the Colville River, 98% at the Kachemach River, and 92% at the Miluveach River by effectively blocking oil in "pools" in the pipeline on the opposite sides of the loops. | This technology would have a longer closing time than the ball valves, and it is not as effective in a fire. Compared to vertical loops, the additional possibility of oil leakage at the mechanical connections of the valves, traditionally an area of concern and maintenance would be added to the project in a roadless area. Additionally, failure to close, while not adding to the risk of a spill, could allow more oil to spill. |
| **COST:** The cost to the applicant of achieving BAT, including consideration of that cost relative to the remaining years of service of the technology in use by the applicant | The system described is proposed and is a base case for comparison. | Additional automation would cost in excess of $100,000. | Additional cost in excess of $50,000. | Additional automation would be cost in excess of $100,000. |
| **AGE AND CONDITION:** The age and condition of technology in use by the applicant | Proposed equipment would be new. | Alternative equipment would be new. | Alternative equipment would be new. | Alternative equipment would be new. |
| **COMPATIBILITY:** Whether each technology is compatible with existing operations and technologies in use by the applicant | Compatible with the proposed project. | Compatible with the proposed project. | Compatible with the proposed project. | Compatible with the proposed project. |

## TABLE 4-2 (CONTINUED): BEST AVAILABLE TECHNOLOGY ANALYSISCRUDE OIL TRANSMISSION PIPELINE SOURCE CONTROL

| BAT EVALUATION CRITERIA | CURRENT METHOD: AUTOMATIC ISOLATION BALL VALVES AND VERTICAL LOOPS TO ELIMINATE DRAIN BACK | ALTERNATE METHOD: ADDITIONAL AUTOMATIC SHUTDOWN BALL VALVES | ALTERNATE METHOD: MANUAL BLOCK VALVES | ALTERNATE METHOD: REPLACEMENT OF AUTOMATIC SHUTDOWN BALL VALVES WITH GATE VALVES |
|---|---|---|---|---|
| **FEASIBILITY:** The practical feasibility of each technology in terms of engineering and other operational aspects | Feasible to implement. | Feasible to implement. | Feasible to implement. | Feasible to implement. |
| **ENVIRONMENTAL IMPACTS:** Whether other environmental impacts of each technology, such as air, land, water pollution, and energy requirements, offset any anticipated environmental benefits | There are no offsetting environmental impacts. | In the event of a spill, there is an increased possibility of discharge to tundra and water from the pipe. | In the event of a spill, there is an increased possibility of discharge to tundra and water from the pipe. | In the event of a spill, there is an increased possibility of discharge to tundra and water from the pipe. |

## TABLE 4-3: BEST AVAILABLE TECHNOLOGY ANALYSIS TANK SOURCE CONTROL

| BAT EVALUATION CRITERIA | CURRENT METHOD: LUBE OIL, COMPLETIONS FLUIDS AND BRINE STORAGE TANKS MANUAL VALVE CLOSURE | ALTERNATIVE METHOD: LUBE OIL, COMPLETIONS FLUIDS AND BRINE STORAGE TANKS AUTOMATED VALVE CLOSURE | CURRENT METHOD: DIESEL TANK AND OFF-SPEC TANK AUTOMATED BALL VALVES | ALTERNATIVE METHOD: DIESEL TANK AND OFF-SPEC TANK AUTOMATED GATE VALVES | ALTERNATIVE METHOD: DIESEL TANK AND OFF-SPEC TANK MANUALLY-OPERATED VALVES |
|---|---|---|---|---|---|
| **AVAILABILITY:** Whether technology is best in use in other similar situations or is available for use by applicant | The product transfer lines for filling tanks are manually operated. Most fill lines are fitted with a check valve to prevent reverse flow. | Technology is available. | Valve closures are automatically initiated when a high-level condition in the tank occurs. A microprocessor-based distributed control system transmitter detects high-level conditions. | Technology is available. | Hardware is available and proven, but manual operation is not a viable option. |
| **TRANSFERABILITY:** Whether each technology is transferable to applicant's operations | Currently installed. | Technology is transferable. | Currently installed. | Technology is transferable. | Technology is transferable. |
| **EFFECTIVENESS:** Whether there is a reasonable expectation each technology will provide increased spill prevention or other environmental benefits | Because operators are required to remain at or near the tank during filling operations, and because an audible and visual alarm is provided should the tank reach a high level, manual intervention is effective in source control. | Additional automation would afford little benefit given the existing filling procedures and requirement for continuous operator presence during the filling operation. | This technology is an effective, proven means of preventing liquid carryover in tanks fed by pipelines or process streams. Automated valves are ball valves that require only one-quarter turn to close and their performance has been proven in dirty service conditions. | Larger gate valves would have a longer closure time than one-quarter turn ball valves and may not close completely after long service in a dirty environment. | Manual valve operation is not a viable option. Diesel and off-spec tanks are in continuous service and around-the-clock staffing with operators is impractical during periods of high fuel demand. |
| **COST:** The cost to the applicant of achieving BAT, including consideration of that cost relative to the remaining years of service of the technology in use by the applicant | Equipment is installed. | Automation of these valves would cost significantly more than the current technology. Also, the operator would still be required to remain at the fill site to oversee the filling operation so there would be no offsetting reduction in operating cost. | Equipment is installed. | Similar cost to the current technology. | Manual valves would cost less than the current technology. |
| **AGE AND CONDITION:** The age and condition of technology in use by the applicant | The system is simple, well proven, and current. New when installed. | Method is more complex, well proven, and current. New when installed. | Automated valves are current. New when installed. | Proven and current technology. New when installed. | Manual valves would be new, proven equipment, but automated valves are typically used universally on process tanks supplied by pipelines. New when installed. |

## TABLE 4-3 (CONTINUED): BEST AVAILABLE TECHNOLOGY ANALYSIS TANK SOURCE CONTROL

| BAT EVALUATION CRITERIA | CURRENT METHOD: LUBE OIL, COMPLETIONS FLUIDS AND BRINE STORAGE TANKS MANUAL VALVE CLOSURE | ALTERNATIVE METHOD: LUBE OIL, COMPLETIONS FLUIDS AND BRINE STORAGE TANKS AUTOMATED VALVE CLOSURE | CURRENT METHOD: DIESEL TANK AND OFF-SPEC TANK AUTOMATED BALL VALVES | ALTERNATIVE METHOD: DIESEL TANK AND OFF-SPEC TANK AUTOMATED GATE VALVES | ALTERNATIVE METHOD: DIESEL TANK AND OFF-SPEC TANK MANUALLY-OPERATED VALVES |
|---|---|---|---|---|---|
| **COMPATIBILITY:** Whether each technology is compatible with existing operations and technologies in use by the applicant | Method is compatible. | Method is compatible. | Method is compatible. | Method is compatible. Gate valves are larger and would require more room to install. | Method is compatible. |
| **FEASIBILITY:** The practical feasibility of each technology in terms of engineering and other operational aspects | Method is feasible. | Method is feasible. | Method is feasible. | Method is feasible. | Method is not feasible. Operating personnel are not available in sufficient numbers and would not provide the reliability of an automated system. |
| **ENVIRONMENTAL IMPACTS:** Whether other environmental impacts of each technology, such as air, land, water pollution, and energy requirements, offset any anticipated environmental benefits | There are no offsetting environmental impacts. | There are no offsetting environmental impacts. | There are no offsetting environmental impacts. | There are no offsetting environmental impacts. | There are offsetting environmental impacts. The risk of tank overflow or a significant process upset would be far higher with a manually operated system. |

## 4.3 TRAJECTORY ANALYSES AND FORECASTS [18 AAC 75.425(e)(4)(A)(i)]

Trajectory analyses and forecasts are described in the ACS *Technical Manual* Tactics T-1 to T-6, and L-11, which are incorporated here by reference.

## 4.4 WILDLIFE CAPTURE, TREATMENT, AND RELEASE PROGRAMS [18 AAC 75.425(e)(4)(A)(i)]

Wildlife capture, treatment, and release programs are described in the ACS *Technical Manual* Tactic L-11 and W-1 through W-5, which are incorporated here by reference. Wildlife protection strategies are in accordance with the *Wildlife Protection Guidelines for Alaska* (Annex G of the Unified Plan).

## 4.5 CATHODIC PROTECTION FOR FIELD CONSTRUCTED OIL STORAGE TANKS [18 AAC 75.425(e)(4)(A)(ii)]

Alpine tanks are shop-fabricated; the regulations requiring cathodic protection on field-constructed tanks do not apply. As such, BAT analysis for cathodic protection is not applicable.

## 4.6 LEAK DETECTION SYSTEM FOR FIELD CONSTRUCTED OIL STORAGE TANKS [18 AAC 75.425(e)(4)(A)(ii)]

Alpine tanks are shop-fabricated; the regulations requiring leak detection on field-constructed tanks do not apply. BAT analysis for leak detection systems is not applicable.

## 4.7 LIQUID LEVEL DETERMINATION [18 AAC 75.425(e)(4)(A)(ii)]

Alpine tanks with automated liquid level determination devices, and regulated by ADEC, are fitted with either an ultrasonic non-contact transmitter or microwave radar non-contact transmitter mounted at the top of the tank, or with a differential pressure transmitter installed at the bottom of the tank. Detection of a high-level condition in the tank triggers local audible and visual alarms, plus remote annunciation in the staffed control room. Most tanks equipped with automated devices are filled with truck fill connections only. Because operators are required to remain at or near the tank during filling operations, and because audible and visual alarms are provided should the tank reach a high level, manual shutdown intervention is effective in source control. The diesel storage tank (No. CF-T-61001) is fitted with dual differential pressure transmitters mounted externally near the bottom of the tank. Detection of a high-level condition in the tank initiates local audible and visual alarms, plus remote annunciation in the control room. The normal source of supply to the tank is the 2-inch-diameter diesel pipeline from Kuparuk. Detection of a high-level condition by either transmitter initiates the closure of the automated tank inlet valve on the incoming products pipeline from Kuparuk. The slop oil tank (No. CF-T-31010) is fitted with a differential pressure transmitter, a radar transmitter, and an ultrasonic transmitter. The differential pressure transmitter is set to alarm at a lower liquid level than the radar and ultrasonic transmitters. Detection of a high level by the differential pressure transmitter annunciates an alarm remotely in the control room and close automated valves on several potential sources of supply to the slop tank. Detection of a higher high level by the microwave radar and ultrasonic transmitter initiates an ESD of the process train. The use of multiple liquid-level determination

devices in these tanks provides redundant (backup) overfill protection, and a means to test the system's functionality. BAT analysis for tank liquid level determination is discussed in Table 4-4.

## TABLE 4-4: BEST AVAILABLE TECHNOLOGY ANALYSIS TANK LIQUID LEVEL DETERMINATION

| BAT EVALUATION CRITERIA | CURRENT METHOD: ULTRASONIC LEVEL TRANSMITTERS | CURRENT METHOD: DIFFERENTIAL PRESSURE LEVEL TRANSMITTERS | ALTERNATE CURRENT METHOD: MICROWAVE RADAR LEVEL TRANSMITTERS | CURRENT METHOD: VISUAL OBSERVATION | ALTERNATE METHOD: CAPACITANCE PROBES | ALTERNATE METHOD: DISPLACER LEVEL SWITCH AND TRANSMITTERS | ALTERNATE METHOD: FLOAT GAUGE |
|---|---|---|---|---|---|---|---|
| **AVAILABILITY:**<br>Whether technology is best in use in other similar situations or is available for use by applicant | Ultrasonic level transmitters on tanks provide local visual and audible annunciation of a high-level alarm and reports the high-level alarm to the Central Control Room. Operators are required to remain at the fill station during filling operation. | Differential pressure level transmitters on tanks provide local visual and audible annunciation of a high-level alarm, plus remote annunciation at the Central Control Room. | Equipment is available and reliable in most level determination applications. | Visual observation is the current method. | Equipment is available and widely used in oilfield applications. | Equipment is available and widely used in oilfield applications. | Equipment is available. |
| **TRANSFERABILITY:**<br>Whether each technology is transferable to applicant's operations | Currently installed in some tanks. | Currently installed in some tanks. | Currently installed in some tanks. | Technology is transferable. | Technology is transferable. | Technology is transferable. | Technology is transferable and is currently in use on some tanks in Alaska. |
| **EFFECTIVENESS:**<br>Whether there is a reasonable expectation each technology will provide increased spill prevention or other environmental benefits | Because operators are required to remain at or near the tanks during the fill operation, and because a high-level condition will trigger both local audible and visual alarms and a remote alarm in the Central Control Room, ultrasonic level transmitters provide adequate level determination for prompt closure of the manual valves. | Continuous monitoring of tank level provides inputs required for microprocessor-based process control system to initiate automated valve closure(s) when high-level conditions occur. | Equipment has acceptable measurement accuracy. Microwaves require no transmission medium and can operate in vacuum and positive-pressure conditions. Measurement results may be affected by vapor, foaming, or turbulent conditions; but low-frequency or modulated-frequency radar pulse devices work well in these conditions. | Equipment is effective with strict adherence to Best Management Practices and local procedure. Tank liquid levels are determined from direct observation through the hatch using a flashlight or other manual device (e.g., tank strap, etc.).<br>As good or better than other "low tech" devices. | Method will work effectively in Alpine service conditions. | Method will work effectively in Alpine service conditions but may require more maintenance for cleaning of displacer. Units would probably require heat tracing for effective operation. | Method has acceptable measurement accuracy. |

## TABLE (CONTINUED): BEST AVAILABLE TECHNOLOGY ANALYSIS TANK LIQUID LEVEL DETERMINATION

| BAT EVALUATION CRITERIA | CURRENT METHOD: ULTRASONIC LEVEL TRANSMITTERS | CURRENT METHOD: DIFFERENTIAL PRESSURE LEVEL TRANSMITTERS | ALTERNATE CURRENT METHOD: MICROWAVE RADAR LEVEL TRANSMITTERS | CURRENT METHOD: VISUAL OBSERVATION | ALTERNATE METHOD: CAPACITANCE PROBES | ALTERNATE METHOD: DISPLACER LEVEL SWITCH AND TRANSMITTERS | ALTERNATE METHOD: FLOAT GAUGE |
|---|---|---|---|---|---|---|---|
| **COST:**<br>The cost to the applicant of achieving BAT, including consideration of that cost relative to the remaining years of service of the technology in use by the applicant | Already in service where appropriate. | Already in service where appropriate. | Already in service where appropriate. | Not applicable. | Costs would be comparable to selected methods. | Costs would be equal to or modestly higher than the selected methods. | Not investigated – see feasibility comments. |
| **AGE AND CONDITION:**<br>The age and condition of technology in use by the applicant | The system is simple, well proven, and current. New when installed. | The technology is current and well proven. New when installed. | The technology is current and proven. New when installed. | Procedures have been in place since 1993 for fuel transfer operations. | The technology is current and proven. New when installed. | The technology is current and proven. New when installed. | The technology is current and proven. |
| **COMPATIBILITY:**<br>Whether each technology is compatible with existing operations and technologies in use by the applicant | Currently installed. | Currently installed. | Currently installed. | Compatible and widely used. Requires no change. | The technology is compatible. | The technology is compatible. | The technology is compatible. |
| **FEASIBILITY:**<br>The practical feasibility of each technology in terms of engineering and other operational aspects. | Currently installed. | Currently installed. | Currently installed. | Feasible and preferred due to potential for electronic or pneumatic systems to experience damage from rough handling. | Method is feasible. | Installation is feasible - would likely require modifications to the tanks that have already been fabricated without any increase in availability or reliability. | ADEC has expressed concern over the use of float devices due to several failures of float devices within the state. |

## TABLE (CONTINUED): BEST AVAILABLE TECHNOLOGY ANALYSIS TANK LIQUID LEVEL DETERMINATION

| BAT EVALUATION CRITERIA | CURRENT METHOD: ULTRASONIC LEVEL TRANSMITTERS | CURRENT METHOD: DIFFERENTIAL PRESSURE LEVEL TRANSMITTERS | ALTERNATE CURRENT METHOD: MICROWAVE RADAR LEVEL TRANSMITTERS | CURRENT METHOD: VISUAL OBSERVATION | ALTERNATE METHOD: CAPACITANCE PROBES | ALTERNATE METHOD: DISPLACER LEVEL SWITCH AND TRANSMITTERS | ALTERNATE METHOD: FLOAT GAUGE |
|---|---|---|---|---|---|---|---|
| **ENVIRONMENTAL IMPACTS:** Whether other environmental impacts of each technology, such as air, land, water pollution, and energy requirements, offset any anticipated environmental benefits | None. | None. | None. | None. | None. | None. | None. |

## 4.8 MAINTENANCE PROCEDURES FOR BURIED STEEL FACILITY OIL PIPING [18 AAC 75.425(e)(4)(A)(ii)]

The buried piping for tank CF-T-50090 at CD-1 is abandoned in-place. However, it is composed of a non-corrosive stainless steel material, wrapped in insulation coated with polyvinyl chloride (PVC), and is centered within a fusion-joined high-density prolyethylene (HDPE) pipe casing. The HDPE pipe casing prevents the piping from contacting soil or water conditions. Corrosion is not anticipated because the pipe is stainless steel and encased in HDPE pipe casing.

## 4.9 PROTECTIVE COATING AND CATHODIC PROTECTION FOR FACILITY OIL PIPING [18 AAC 75.425(e)(4)(A)(ii)]

### 4.9.1 Pipeline Corrosion Protective (Anti Corrosion) Wrapping or Coating

As required by 18 AAC 75.080(d) and 18 AAC 75.080(e)(2)(A), the buried pipelines in the horizontal directional drilling (HDD) segment under the Colville River are protected from external corrosion by an external coating. Available technologies for pipeline wrapping or coating are:

- Dual-layer fusion bonded epoxy (FBE) for corrosion and mechanical protection,
- Conventional single-layer FBE for corrosion protection,
- Paint,
- Ceramic,
- Cold tar enamel, and
- Neoprene or foam.

Of these six technologies, dual-layer FBE is considered BAT based on the physical properties of each technology in relation to the physical environment of the Alpine pipelines and the cost of FBE relative to a neoprene or foam coating system.

Paint and ceramic coatings are not effective for the pipelines because these materials are brittle. The pipelines require a coating material that is ductile, because the pipelines may be subjected to high-bending strains potentially caused by permafrost thaw settlement. Neoprene or foam-type coatings are ductile and durable; however, they are more costly than FBE coatings. Also, neoprene and foam coatings reduce the weight of the pipelines, and more cost would be incurred to provide additional weight to the pipelines for stability during pipe-laying operations.

Both dual-layer and single-layer FBE coatings are ductile; however, dual-layer FBE, composed of an inner layer of conventional FBE for corrosion protection and an outer layer of impact-resistant FBE for mechanical protection, is more durable (hence more transferable) than a single-layer FBE coating. Dual-layer FBE has been used on other pipelines and is readily available for the Alpine pipelines. The dual-layer FBE coating's inner layer is the conventional FBE material that has been effective as a corrosion protection coating on marine pipelines. Both layers, which are feasible to apply, have a low coating breakdown factor that causes less impact to the environment while making the dual-layer FBE coating compatible with sacrificial anodes. High coating breakdown factors adversely affect sacrificial anode systems. The cost to apply the dual-layer FBE coating (in a new condition) is considered reasonable by COPA. Therefore, a dual-layer FBE coating

is considered BAT suited for the Alpine pipelines. If it is determined that the durability of the impact-resistant layer of FBE is not required, a single layer of corrosion-protective FBE may be used.

The buried piping for tank CF-T-50090 at CD-1, which is abandoned in-place, is not wrapped or coated for corrosion protection. The piping is composed of a non-corrosive stainless steel material, wrapped in insulation coated with PVC, and is centered within a fusion-joined HDPE pipe casing. The HDPE pipe casing prevents the piping from contacting soil or water conditions. The piping is subject to an ADEC compliance waiver of cathodic protection and protective wrapping/coating (see Section 2.6).

### 4.9.2 Cathodic Protection System

The buried piping for tank CF-T-50090 at CD-1, which is abandoned in-place, does not have cathodic protection. The piping is composed of a non-corrosive stainless steel material, wrapped in insulation coated with PVC, and is centered within a fusion-joined HDPE pipe casing. The HDPE pipe casing prevents the piping from contacting soil or water conditions. The piping is subject to an ADEC compliance waiver of cathodic protection and protective wrapping/coating (see Section 2.6).

## 4.10 CORROSION SURVEYS [18 AAC 75.425(e)(4)(A)(ii)]

Not applicable; cathodic protection is not installed on facility oil piping.

## 4.11 PIPELINE LEAK DETECTION, MONITORING, AND OPERATIONS [18 AAC 75.425(e)(4)((A)(iv)]

### 4.11.1 Aboveground Crude Oil Transmission Pipeline

As required by 18 AAC 75.425(e)(4)(A)(iv), a BAT review is provided for leak detection technologies applicable to the Alpine crude oil transmission pipeline and is discussed in Table 4-5. These technologies are:

- Mass Balance Line Pack Compensation (MBLPC) – included for Alpine crude oil transmission pipeline,
- Flow and Pressure Analysis – included for Alpine crude oil transmission pipeline,
- Visual Surveillance – included for Alpine crude oil transmission pipeline,
- Negative Pressure Wave Monitoring (NPWM) (acoustic monitoring system)
- Mass Balance (MB),
- Acoustic Emissions – monitoring based on measured sound data, and
- Real Time Transient Model (RTTM).

The rationale in determining the most appropriate leak detection system for North Slope transmission lines is based on operation philosophy, and criteria stipulated in the BAT analysis. First, there must be redundancy (i.e., reliance will not be placed on a single leak detection system). The technology must be state-of-the-art and capable of immediate detection of a sudden, large volume loss of product and detection of a low-threshold, chronic (pinhole) leak. The system also must be commercially available, in use on similar

pipeline systems, comprised of two leak detection systems that are readily integrated with each other, and available from a vendor with a proven track record.

A combination MBLPC and flow and pressure analysis automated leak detection systems, and visual surveillance is the most appropriate system for the Alpine crude oil transmission pipeline. The combination of these leak detection systems provides the ability to rapidly detect large and small volume leaks. The LINEGUARD™ system provides the monitoring capability of a combination MBLPC and flow and pressure analysis system needed for a long, high-pressure, high-flow rate production crude oil transmission pipeline such as the Alpine crude oil transmission pipeline. Further discussion of the leak detection methods is provided in Section 2.5.

The combination of these technologies achieves a minimum leak detection threshold limit of 1% when used in conjunction with:

- A proving loop for assuring meter accuracy.
- The crude oil transmission pipeline's selected meters, which will provide the best available meter accuracy (1% accuracy with repeatability of 0.02%). Currently, custody transfer meters measure flow upstream of the oil pipeline pumps, and flow meters measure flow immediately downstream of the pipeline at Central Processing Facility 2.
- Relatively stable pump performance.

This 1% limit, which can be provided by the selected overall leak detection system listed above for the Alpine crude oil transmission pipeline, meets the minimum required leak detection threshold limit of 1% of the oil pipeline's daily throughput as specified by 18 AAC 75.055(a)(1).

### 4.11.2 Belowground Crude Oil Transmission Pipeline

The leak detection systems that apply to the aboveground pipeline also apply to the belowground piping. In addition, the annular space in the casing at the Colville River crossing is provided with conduit for leak detection sensors. The sensors detect fluids entering the annular space. The system is intended to detect oil from the carrier pipes, but the MBLPC and flow and pressure analysis automated leak detection systems are the primary leak detection system. The secondary system is not subject to BAT.

The technology uses a small sensor that measures the refraction of light through the liquids. Each liquid has a different index of refraction, allowing the sensor to distinguish between oil and water. The sensor is sensitive enough to distinguish between different types of hydrocarbons. A fiber optic cable connects the sensor to the control panel and carries the light between the two. The system is inherently safe because no electrical power is used in the annulus. The sensor automatically resets and does not require removal after wetting.

TABLE 4-5: BEST AVAILABLE TECHNOLOGY ANALYSIS LEAK DETECTION IN CRUDE OIL TRANSMISSION PIPELINE

| BAT EVALUATION CRITERIA | EXISTING METHOD: MBLPC | EXISTING METHOD FLOW AND PRESSURE ANALYSIS | EXISTING METHOD VISUAL SURVEILLANCE | ALTERNATE METHOD NPWM | ALTERNATE METHOD MASS BALANCE (MB) | ALTERNATE METHOD ACOUSTIC EMISSIONS MONITORING BASED ON MEASURED SOUND DATA | ALTERNATE METHOD RTTM |
|---|---|---|---|---|---|---|---|
| **AVAILABILITY:** Whether technology is best in use in other similar situations or is available for use by applicant | MBLPC is widely used on crude oil pipelines and is commercially available. | Technology is simple and inexpensive and is commercially available. | Technology is very simple and available. | NPWM is commercially available and performs best under steady-state flow conditions. It has been used on existing production oil pipelines at leak detection thresholds of 3% to 4% of daily oil throughput. | MB has been widely used on oil pipelines. It performs best under steady-state flow conditions. However, vendors are now recommending MBLPC over MB because MBLPC offers better performance than MB. | Acoustic emissions is commercially available and reportedly applicable to crude oil. However, the technology has never been installed on a crude oil transmission pipeline. | RTTM is used on oil pipelines; however, it is best suited for transient flow conditions. |

TABLE 4-5 (CONTINUED): BEST AVAILABLE TECHNOLOGY ANALYSIS LEAK DETECTION IN CRUDE OIL TRANSMISSION PIPELINE

| BAT EVALUATION CRITERIA | EXISTING METHOD: MBLPC | EXISTING METHOD FLOW AND PRESSURE ANALYSIS | EXISTING METHOD VISUAL SURVEILLANCE | ALTERNATE METHOD NPWM | ALTERNATE METHOD MASS BALANCE (MB) | ALTERNATE METHOD ACOUSTIC EMISSIONS MONITORING BASED ON MEASURED SOUND DATA | ALTERNATE METHOD RTTM |
|---|---|---|---|---|---|---|---|
| **TRANSFERABILITY:** Whether each technology is transferable to applicant's operations | MBLPC is widely used on oil pipelines. Software is compatible with existing Supervisory Control and Data Acquisition (SCADA) systems, it requires basic pipeline parameter and configuration set-up, and it requires no maintenance.<br>It performs best if:<br>1. Transient flow conditions do not occur frequently.<br>2. There is no multi-phase flow.<br>3. There is no slackline flow. | Technology is used on oil pipelines. Typically used as a adjunct to a line or mass balance system.<br>Can use existing pressure or flow meters.<br>It performs best when:<br>1. Transient flow conditions do not occur frequently.<br>2. There is no multi-phase flow.<br>3. There is no slackline flow. | Currently used. | NPWM technology can be used on oil pipelines if:<br>1. The oil pipeline operates in a steady-state mode.<br>2. There is no batching.<br>3. There is no multi-phase flow.<br>4. There is no slackline flow.<br>5. NPWM systems work best with a maximum pressure wave transducer spacing between 2 to 10 miles apart.<br>6. Optimal data sampling frequency of once every 6 seconds or less. Leak locating requires data sampling frequency of once every 0.25 seconds. Effective leak detection is dependent on the amount of pressure flow deviations in the pipeline. | MB technology is widely used on oil pipelines. It performs best if:<br>1. The oil pipeline operates in a steady-state mode.<br>2. There is no batching.<br>3. There is no multi-phase flow.<br>4. There is no slackline flow.<br>5. Temperature remains constant.<br>6. Pipeline is relatively short (on the order of 20 miles long). | Acoustic emissions is reportedly transferable to crude oil transmission pipelines. It performs best if:<br>1. There is no multi-phase flow.<br>2. There is no slackline flow.<br>3. Transducers are spaced along the pipeline at intervals less than 300 feet.<br>4. The signal velocity of the product within the pipe is known.<br>5. Background noise, if minimized or filtered.<br>6. Large pressure transients do not occur frequently. | RTTM is applicable to crude oil pipelines. However, it is more appropriate for multi-phase flow conditions, transient flow conditions, and pipeline networks. |

## TABLE 4-5 (CONTINUED): BEST AVAILABLE TECHNOLOGY ANALYSIS LEAK DETECTION IN CRUDE OIL TRANSMISSION PIPELINE

| BAT EVALUATION CRITERIA | EXISTING METHOD: MBLPC | EXISTING METHOD FLOW AND PRESSURE ANALYSIS | EXISTING METHOD VISUAL SURVEILLANCE | ALTERNATE METHOD NPWM | ALTERNATE METHOD MASS BALANCE (MB) | ALTERNATE METHOD ACOUSTIC EMISSIONS MONITORING BASED ON MEASURED SOUND DATA | ALTERNATE METHOD RTTM |
|---|---|---|---|---|---|---|---|
| **EFFECTIVENESS:** Whether there is a reasonable expectation each technology will provide increased spill prevention or other environmental benefits | MBLPC can detect leaks that are 1% of daily oil throughput. MBLPC system performance is dependent on the accuracy of oil pipeline flow meters. With flow meter calibration, detection of leaks smaller than the 1% threshold can be achieved. MBLPC can detect a 250-barrel leak over a 5-minute interval, a 600-barrel leak over a 1-hour interval, and a 1,500-barrel leak over a 24-hour interval. | Not a mass balance method, so there is no calculation of leak rate. Uses statistical methods and digital signal to identify patterns of change in pressure or flow that may indicate presence of a leak.<br>Rapid detection of significant leaks is possible. Sensitivity depends on the system's flow stability and the location of the leak relative to the sensing devices.<br>Algorithms can utilize calculated flow rates with measured flow and pressures to estimate position or location of a leak. | An effective means of identifying a leak that can be detected either visually or by infrared sensors. Sometimes leaks occur that are below the threshold limit of the leak detection system and are spotted by visual detection. Best when utilized in conjunction with an automated leak detection system. | This method does not provide improved leak detection over other methods. Detection threshold is approximately 3% to 4% of daily throughput for liquid lines and 10% to 15% of daily throughput for gas lines. | This method is less effective than MBLPC. | This method can detect leaks that are less than 1% of daily throughput. Identification and elimination of external ambient and pipeline operating noise is essential for an accurate acoustic assessment (leak detection). | This method can detect leaks that are 1% of the daily throughput even when the flow is transient. |
| **COST:** The cost to the applicant of achieving BAT, including consideration of that cost relative to the remaining years of service of the technology is use by the applicant. | Approximate cost is $120,000 for software and support; assumes equipment is already in place for SCADA and metering. | Technology is typically packaged with other systems. | The cost would be based on trips to cover the pipeline right-of-way. No up-front investment. | Minimum cost of $130,000. | Approximate cost is $50,000. | Minimum cost is $90,000. | Approximate cost is $350,000. RTTM is the most expensive system to implement and maintain. |

## TABLE 4-5 (CONTINUED): BEST AVAILABLE TECHNOLOGY ANALYSIS LEAK DETECTION IN CRUDE OIL TRANSMISSION PIPELINE

| BAT EVALUATION CRITERIA | EXISTING METHOD: MBLPC | EXISTING METHOD FLOW AND PRESSURE ANALYSIS | EXISTING METHOD VISUAL SURVEILLANCE | ALTERNATE METHOD NPWM | ALTERNATE METHOD MASS BALANCE (MB) | ALTERNATE METHOD ACOUSTIC EMISSIONS MONITORING BASED ON MEASURED SOUND DATA | ALTERNATE METHOD RTTM |
|---|---|---|---|---|---|---|---|
| **AGE AND CONDITION:** The age and condition of technology in use by the applicant | Method is current. | Method is current. | Method is current. | The required software and hardware would be new when installed. | The required software and hardware would be new when installed. | The required software and hardware would be new when installed. | The required software and hardware would be new when installed. |
| **COMPATIBILITY:** Whether each technology is compatible with existing operations and technologies in use by the applicant | MBLPC is compatible with SCADA systems and can be combined with flow and pressure analysis. | Technology is compatible with SCADA systems and is typically combined with MBLPC. | Compatible because of ready access by road system and by aerial overflight by aircraft. | NPWM is compatible with SCADA systems. | MB is compatible with SCADA systems. | Acoustic emissions is compatible with SCADA systems. | RTTM is compatible with SCADA systems. |
| **FEASIBILITY:** The practical feasibility of each technology in terms of engineering and other operational aspects | MBLPC is routinely used on relatively short pipelines. It is used on long pipelines when the pipeline is split into segments, each bound by flow and/or pressure meters. | Technology is feasible and appropriate to the application of pipeline leak detection and leak location.<br><br>Is not feasible as a method to calculate leak rate. | Method is feasible and routinely used. | NPWM is feasible for oil pipelines. It does not offer the same effectiveness in detecting leaks less than 1% of daily oil throughput. | MB is simple to implement on relatively short pipelines (approximately 20 miles).<br><br>It is the least expensive system to install on the oil pipeline. | Acoustic emissions is reportedly transferable to crude oil transmission pipelines and would therefore be feasible. | RTTM is a relatively complex and costly system to implement on oil pipelines. It requires system calibration to tune detection accuracy and additional data measurements to calculate system response. Operators need higher level training to provide reliable operation. |

## TABLE 4-5 (CONTINUED): BEST AVAILABLE TECHNOLOGY ANALYSIS LEAK DETECTION IN CRUDE OIL TRANSMISSION PIPELINE

| BAT EVALUATION CRITERIA | EXISTING METHOD: MBLPC | EXISTING METHOD FLOW AND PRESSURE ANALYSIS | EXISTING METHOD VISUAL SURVEILLANCE | ALTERNATE METHOD NPWM | ALTERNATE METHOD MASS BALANCE (MB) | ALTERNATE METHOD ACOUSTIC EMISSIONS MONITORING BASED ON MEASURED SOUND DATA | ALTERNATE METHOD RTTM |
|---|---|---|---|---|---|---|---|
| **ENVIRONMENTAL IMPACTS:** Whether other environmental impacts of each technology, such as air, land, water pollution, and energy requirements, offset any anticipated environmental benefits | None. Implementation of this system will significantly reduce oil loss to the environment if a leak were to occur. MBLPC is best suited to detect small, chronic leaks that fall below a threshold set under flow and pressure analysis systems. | None. In conjunction with MBLPC, implementation of this system will significantly reduce oil loss to the environment if a leak were ever to occur. | Visual identification adds the ability to detect small leaks. Therefore, when used as a complement to other automated leak detection systems, it provides an environmental benefit. | With NPWM, there is only a single opportunity to detect a leak, when the leak initiates. Therefore, once the expansion wave passes the system's monitoring locations, the opportunity for detection is gone. If this detection opportunity is missed, the environmental impact could be large. | MB is an effective leak detection system. Implementation will significantly reduce oil loss to the environment if a leak were ever to occur. However, MBLPC offers improved performance over MB.<br><br>The system requires data collection in 30 or 60 second intervals for oil lines. | None. With the required elimination of external ambient and pipeline operating noise, acoustic emissions is an effective leak detection system. | None. Implementation will significantly reduce oil loss to the environment if a leak were ever to occur. |

# PART 5 RESPONSE PLANNING STANDARD [18 AAC 75.425(e)(5)]

## 5.1 STORAGE TANK RUPTURE

The adjusted RPS volume for the oil storage tanks at Alpine is 1,320 barrels of diesel as calculated below.

| | |
|---|---|
| Initial RPS volume (volume capacity of the tank) | 3,300 bbl |
| 60% adjust for secondary containment | -1,980 bbl |
| Adjusted RPS volume | **1,320 bbl** |

## 5.2 PRODUCTION WELL BLOWOUT [18 AAC 75.434]

The production facility RPS volume was calculated using publicly available data from the Alaska Oil and Gas Conservation Commission.

Alpine oil production data from November 1, 2015 to January 31, 2017 was reviewed to determine the maximum producing well. Well CD5-313 had the highest oil production rate, with an average of 9,775 bopd. Oil production wells at Alpine are equipped for assisted lift; however new wells (such as CD5-313) tapping new reservoir development areas tend to flow at high rates during the first years of production, followed by continuous decline as formation gas is depleted and reservoir pressure changes. The RPS volume was determined for a well without assisted lift, at an average rate of 10,000 bopd:

| | |
|---|---|
| Daily discharge rate | 10,000 bopd |
| Number of days | x 15 days |
| RPS volume | **150,000 bbl** |

The receiving environment is a gravel production well pad surrounded by tundra and lakes in the summer season, and snow and ice on frozen tundra and frozen lake surfaces in the winter season. Oil travels from the well in an aerial plume.

## 5.3 CRUDE OIL TRANSMISSION PIPELINE SPILL TO MILUVEACH RIVER [18 AAC 75.436]

The adjusted RPS volume for a spill from the Alpine crude oil transmission pipeline at the Miluveach River crossing is 2,830 barrels, all of which reaches open water via a pipeline rupture directly over the river. This value was calculated using the following equation from 18 AAC 75.436:

RPS volume = (L - H) * C+ FR * (TD + TSD)

**Where:**

L = pipeline length between pumping or receiving station valves;

H = pipeline hydraulic characteristics due to terrain profile;

C = pipeline capacity in bbl per linear measure;

FR = pipeline flow rate in bbl per time period;

TD = estimated time to detect a spill event;

TSD = time needed to shut down the pipeline pump or system;

L = 182,676 feet between valves (vertical loops meet requirement of 49 CFR 195);

H = 179,359 feet of the pipeline that will not drain*;
*Hydraulic gradients are determined by the linear distance between vertical loops along the pipeline. See Section 1.8 and Table 3-2 for locations and distances between vertical loops.

C = 0.17 bbl per linear foot of pipeline;

FR = 69.44 bbl per minute based on a flow rate of 100,000 bbl per day;

TD = 30 minutes; and

TSD = 15 minutes.

**Therefore:**

RPS = [(182,676 ft - 179,359 ft) x (0.17 bbl/ft)] + [(69.44 bbl/min) x (30 min + 15 min)]

= **3,689 bbl**

| | |
|---|---|
| RPS volume entering open water | 3,689 bbl |
| Less 5% prevention credit, drug and alcohol testing [18 AAC 75.436(c)(1)] | (184 bbl) |
| Less 5% prevention credit, on-line leak detection [18 AAC 75.436(c)(3)] | (175 bbl) |
| Less 15% prevention credit, smart pig system [18 AAC 75.436(c)(4)(B)] | (500bbl) |
| **Adjusted RPS volume entering open water** | **2,830 bbl** |

In the event of a catastrophic pipeline rupture, the Pipeline Controller would immediately detect a change in pipeline operating pressure while simultaneously sensing a total loss of flow at the CPF2 metering skid. The Alpine Pipeline would be shut in immediately. Subsequent signal verification, shutdown support, and field verification would follow. For planning purposes, 45 minutes is assumed for detection and shutdown combined, although the period may be a few minutes.

## 5.4 CRUDE OIL TRANSMISSION PIPELINE SPILL TO KACHEMACH RIVER [18 AAC 75.436]

The adjusted RPS volume for a spill from the Alpine crude oil transmission pipeline at the Kachemach River crossing is 244 barrels, all of which reach open water via a pipeline rupture directly over the river. This value was calculated using the following equation from 18 AAC 75.436:

RPS volume = (L - H) * C+ FR * (TD + TSD)

**Where:**

L = pipeline length between pumping or receiving station valves;

H = pipeline hydraulic characteristics due to terrain profile;

C = pipeline capacity in bbl per linear measure;

FR = pipeline flow rate in bbl per time period;

TD = estimated time to detect a spill event;

TSD = time needed to shut down the pipeline pump or system;

L = 182,676 feet between valves (vertical loops meet requirement of 49 CFR 195);

H = 181,421 feet of the pipeline that will not drain*;

* Hydraulic gradients are determined by the linear distance between vertical loops along the pipeline. See Section 1.8 and Table 3-2 for locations and distances between vertical loops.

| | | |
|---|---|---|
| C | = | 0.17 bbl per linear foot of pipeline; |
| FR | = | 69.44 bbl per minute based on a flow rate of 100,000 bbl per day; |
| TD | = | 1 minute; and |
| TSD | = | 30 seconds (0.5 minute). |

**Therefore:**

RPS = [(182,676 ft – 181,421 ft) x (0.17 bbl/ft)] + [(69.44 bbl/min) x (1 min + 0.5 min)]

= **318 bbl**

| | |
|---|---|
| RPS volume entering open water | 318 bbl |
| Less 5% prevention credit, drug, and alcohol testing [18 AAC 75.436(c)(1)] | (16 bbl) |
| Less 5% prevention credit, online leak detection [18 AAC 75.436(c)(3)] | (15 bbl) |
| Less 15% prevention credit, smart pig system [18 AAC 75.436(c)(4)(B)] | (43 bbl) |
| Adjusted RPS volume entering open water | **244 bbl** |

In the event of a catastrophic pipeline rupture, the Pipeline Controller would immediately detect a change in pipeline operating pressure while simultaneously sensing a total loss of flow at the CPF2 metering skid. The Alpine Pipeline would be shut in immediately. Subsequent signal verification, shutdown support, and field verification would follow. For planning purposes, 45 minutes is assumed for detection and shutdown combined, although the period may be a few minutes.

## 5.5 CRUDE OIL TRANSMISSION PIPELINE SPILL TO COLVILLE RIVER [18 AAC 75.436]

The adjusted RPS volume for a spill from the Alpine crude oil transmission pipeline at the Colville River crossing is 772 barrels, none of which reaches open water. The distance between vertical loop horizontal directional drilling West and the river bank is such that an aboveground pipeline rupture of this volume likely would not result in oil reaching the Colville River. The oil would saturate the tundra surface surrounding the rupture site. This value was calculated using the following equation from 18 AAC 75.436:

RPS volume = (L - H) * C+ FR * (TD + TSD)

**Where:**

| | | |
|---|---|---|
| L | = | pipeline length between pumping or receiving station valves; |
| H | = | pipeline hydraulic characteristics due to terrain profile; |
| C | = | pipeline capacity in bbl per linear measure; |

| | | |
|---|---|---|
| FR | = | pipeline flow rate in bbl per time period; |
| TD | = | estimated time to detect a spill event; |
| TSD | = | time needed to shut down the pipeline pump or system; |
| L | = | 182,676 feet between valves (vertical loops meet requirement of 49 CFR 195); |
| H | = | 177,372 feet of the pipeline that will not drain*; |

* Hydraulic gradients are determined by the linear distance between vertical loops along the pipeline. Value is calculated by subtracting the distance between Vertical loops horizontal directional drilling west and east from the total length between valves. See Section 1.8 and Table 3-2 for locations and distances between vertical loops.

| | | |
|---|---|---|
| C | = | 0.17 bbl per linear foot of pipeline; |
| FR | = | 69.44 bbl per minute based on a flow rate of 100,000 bbl per day; |
| TD | = | 1 minute; and |
| TSD | = | 30 seconds (0.5 minute). |

**Therefore:**

RPS = [(182,676 ft – 177,372 ft) x (0.17 bbl/ft)] + [(69.44 bbl/min) x (1 min + 0.5 min)]

= **1,006 bbl**

| | |
|---|---|
| RPS volume entering land | 1,006 bbl |
| Less 5% prevention credit, drug, and alcohol testing [18 AAC 75.436(c)(1)] | (50 bbl) |
| Less 5% prevention credit, online leak detection [18 AAC 75.436(c)(3)] | (48 bbl) |
| Less 15% prevention credit, smart pig system [18 AAC 75.436(c)(4)(B)] | (136 bbl) |
| Adjusted RPS volume entering land | **772 bbl** |
| **RPS volume entering open water** | **0 bbl** |

In the event of a catastrophic pipeline rupture, the Pipeline Controller would immediately detect a change in pipeline operating pressure while simultaneously sensing a total loss of flow at the CPF2 metering skid. The Alpine Pipeline would be shut in immediately. Subsequent signal verification, shutdown support, and field verification would follow. For planning purposes, 45 minutes is assumed for detection and shutdown combined, although the period may be a few minutes.

## APPENDIX A

## FEDERAL RESPONSE PLANS

## OIL POLLUTION ACT OF 1990 ADDENDUM

## U.S. DEPARTMENT OF TRANSPORTATION

## U.S. ENVIRONMENTAL PROTECTION AGENCY

## AND

## U.S. DEPARTMENT OF THE INTERIOR BUREAU OF LAND MANAGEMENT

**BLANK PAGE**

U.S. Department
of Transportation
**Pipeline and Hazardous
Materials Safety Administration**

1200 New Jersey Avenue, S.E.
Washington, D.C. 20590

September 11, 2017

Jeanie Shifflet
ConocoPhillips Alaska, Inc.
700 G Street
Anchorage, AK 94510-0360

**RE: LETTER OF APPROVAL: Alpine Development Participating Area North Slope, Alaska Oil Discharge Prevention and Contingency Plan, Sequence Number: 1476, June 2017**

Dear Ms. Shifflet:

The Pipeline and Hazardous Materials Safety Administration (PHMSA) has received and reviewed ConocoPhillips Alaska, Inc.'s amended Alpine Development Participating Area North Slope, Alaska Oil Discharge Prevention and Contingency Plan dated June 2017. We conclude that the plan complies with PHMSA's regulations concerning onshore oil pipelines found at 49 Code of Federal Regulations (CFR) Part 194. Your Response Plan is approved.

This approval is valid for five years from the date of this letter. If discrepancies are found during PHMSA inspections, or if new or different operating conditions or information would substantially affect the implementation of this plan, you will be required to resubmit a revised plan. See 49 CFR § 194.121(b).

Should you have any questions or concerns, please contact me at (202) 366-4595 or by email at PHMSA.OPA90@dot.gov. Please include the sequence number and your PHMSA Operator Identification Number on any future correspondence.

Sincerely,

David K. Lehman, Director
Oil Spill Preparedness and Emergency Support Division
Office of Pipeline Safety

cc: PHMSA Western Region

BLANK PAGE

# U.S. DEPARTMENT OF TRANSPORTATION

## ALPINE PIPELINE SYSTEM RESPONSE PLAN

### CROSS REFERENCE TO [49 CFR 194, Subpart B]

| REGULATION SECTION (49 CFR) | SECTION TITLE | ODPCP PLAN SECTION |
|---|---|---|
| **194.103** | **Significant and substantial harm; operator's statement** | |
| (a) | Identification of line sections that might cause significant and substantial harm to the environment in the event of a discharge | p. A-6, Section 2.3, Table 2-6, Section 3.1.4 |
| (b) | Response zone(s) considered to cause significant and substantial harm to the environment in the event of a discharge. | p. A-6 |
| (c) | Significant and substantial harm criteria. | p. A-6 |
| **194.105** | **Worst case discharge** | |
| (a) | The worst case discharge (WCD) and the methodology, including calculations, used to arrive at the volume | p. A-7 |
| (b)(1) | Pipeline release WCD | p. A-7, Sections 1.6, 5.3, 5.4, and 5.5 |
| (b)(2) | Historical discharge WCD | p. A-7 |
| (b)(3) | Largest breakout tank WCD | p. A-7; Alpine does not operate a breakout tank |
| (b)(4) | Secondary containment prevention credits for breakout tank WCD. | Not applicable |
| **194.107** | **General response plan requirements** | |
| (a) | Resources for responding, to the maximum extent practicable, to a worst-case discharge and to the substantial threat of such a discharge | p. A-4, A-8, Sections 1.5, 1.6, and 3.6 |
| (b)(1) | Certification that the response plan is consistent with the NCP | p. A-5 |
| (b)(1)(i) | Demonstrate an operator's clear understanding of the function of the Federal response structure, including procedures to notify the National Response Center reflecting the relationship between the operator's response organization's role and the Federal On Scene Coordinator's role in pollution response; | Sections 1.1, 1.2, and 3.3 |
| (b)(1)(ii) | Establish provisions to ensure the protection of safety at the response site; and | Section 1.3 |
| (b)(1)(iii) | Identify the procedures to obtain any required Federal and State permissions for using alternative response strategies such as in-situ burning and dispersants as provided for in the applicable ACPs; and | COPA does not consider the use of dispersants in this FRP. Information for in-situ burning is provided in: Sections 1.7 and 3.7 |
| (b)(2) | As a minimum, to be consistent with the applicable ACP the plan must | -- |
| (b)(2)(i) | Address the removal of a worst case discharge and the mitigation or prevention of a substantial threat of a worst case discharge; | Sections 1.6 and 3.6 |
| (b)(2)(ii) | Identify environmentally and economically sensitive areas; | Sections 1.6 and 3.10 |
| (b)(2)(iii) | Describe the responsibilities of the operator and of Federal, State and local agencies in removing a discharge and in mitigating or preventing a substantial threat of a discharge; and | Sections 1.1, 1.2, 1.6, 2.1, 2.3, 2.4, 2.5, 3.3, 3.6, 3.7, 3.9, and 3.10 |
| (b)(2)(iv) | Establish the procedures for obtaining an expedited decision on use of dispersants or other chemicals. | Not applicable. COPA does not consider use of dispersants in this FRP |
| (c)(1)(i) | Information Summary as required by 194.113 | p. A-6 |
| (c)(1)(ii) | Immediate notification procedures | Sections 1.1, 1.2, and 3.3 |
| (c)(1)(iii) | Spill detection and mitigation procedures | Sections 2.1.8 and 2.5 |

## CROSS REFERENCE TO
## [49 CFR 194, Subpart B]

| REGULATION SECTION (49 CFR) | SECTION TITLE | ODPCP PLAN SECTION |
|---|---|---|
| (c)(1)(iv) | Name, address, telephone number of oil spill response organization | Section 3.8 |
| (c)(1)(v) | Response activities and response resources | p. A-4, A-8, Sections 1.1, 1.2, 1.5, 3.3, and 3.6 |
| (c)(1)(vi) | Names and telephone numbers of federal, state, and local agencies with pollution control responsibilities or support | Section 1.2; Table 1-2 |
| (c)(1)(vii) | Training procedures | Sections 2.1.1 and 3.9 |
| (c)(1)(viii) | Equipment testing | Section 3.6.3 |
| (c)(1)(ix) | Drill types, schedules, and procedures | Section 3.9.6 |
| (c)(1)(x) | Plan review and update procedures | Introduction |
| (c)(2) | Response zone appendices | Not applicable, entire pipeline is a single response zone |
| (c)(3) | Description of response management organization, span of control, clear chain of command, and trained response personnel. | Sections 3.3 and 3.9 |
| **194.109** | **Submission of state response plans.** | |
| (b)(1) | A plan submitted under this section must have an information summary required by §194.113; | p. A-6 |
| (b)(2) | List the names or titles and 24-hour telephone numbers of the qualified individual(s) and at least one alternate qualified individual(s); and | p. A-6 |
| (b)(3) | Ensure through contract or other approved means the necessary private personnel and equipment to respond to a worst case discharge or a substantial threat of such a discharge. | Section 3.8 |
| **194.113** | **Information Summary** | |
| (a)(1) | Name and address of operator | p. A-6 |
| (a)(2) | Listing and description of response zones | p. A-6 |
| (b) | The information summary for the response zone appendix.... | Not applicable. Refer to 194.107(c)(1)(i) through 194.107(c)(1)(x) in this cross-reference. |
| **194.115** | **Response Resources** | |
| (a) | Identify and ensure, by contract or other approved means the recourses necessary to remove, to the maximum extent practicable, a WCD and to mitigate or prevent a substantial threat of a WCD. | Sections 1.5, 1.6, 3.6, 3.8, and 3.9 |
| (b) | Identify the response resources which are available to respond within the time specified, after discovery of a worst case discharge, or to mitigate the substantial threat of such a discharge as follows: Tier 1 – 12 hrs; Tier 2 – 36 hrs; and Tier 3 – 60 hrs. | Sections 1.5, 1.6, 3.6, and 3.9 |
| **194.117** | **Training** | |
| (a)(1) | All personnel know: | |
| (a)(1)(i) | Their responsibilities under the response plan, | Sections 2.1.1 and 3.9 |
| (a)(1)(ii) and (iii) | Name and address of, and the procedure for contacting, the operator...(and) the qualified individual on a 24-hour basis. | p. A-6, Sections 1.1 and 3.3 |
| (a)(2) | Reporting personnel know: | |
| (a)(2)(i) | Content of the information summary of the response plan, | Sections 2.1.1 and 3.9 |
| (a)(2)(ii) | The toll-free number for the National Response Center, | Section 1.2 |
| (a)(2)(iii) | The notification process; and | Section 1.2 |

## CROSS REFERENCE TO
## [49 CFR 194, Subpart B]

| REGULATION SECTION (49 CFR) | SECTION TITLE | ODPCP PLAN SECTION |
|---|---|---|
| (a)(3) | Personnel engaged in response activities know: | |
| (a)(3)(i) | Characteristics and hazards of the oil discharged, | Section 3.10.1 |
| (a)(3)(ii) | Conditions that are likely to worsen emergencies, including the consequences of facility malfunctions or failures, and the appropriate corrective action. | Section 3.4, Section 3.9 |
| (a)(3)(iii) | Steps necessary to control any accidental discharge of oil and to minimize the potential for fire, explosion, toxicity, or environmental damage, and | Sections 1.1, 1.3, and 1.6 |
| (a)(3)(iv) | Proper firefighting procedures and use of equipment, fire suits, and breathing apparatus. | Sections 1.6 and 3.9.4 |
| (b) | Maintain a training record for each individual that has been trained as required by this section and maintain the records in the following manner as long as the individual has responsibility under the response plan: | Sections 2.1.1 and 3.9.5 |
| (b)(1) | Records for operator personnel must be maintained at the operator's headquarters; and | Sections 2.1.1 and 3.9.5 |
| (b)(2) | Records for personnel engaged in response, other than operator personnel, shall be maintained as determined by the operator. | Sections 2.1.1 and 3.9.5 |
| (c) | Nothing in this section relieves the operator from the responsibility to ensure that all response personnel are trained to meet the OSHA standards for emergency response operations. | Section 3.9 |
| **195.440** | **Public Awareness** | p. A-8 |

## U.S. DOT CERTIFICATION OF RESPONSE PREPAREDNESS

# CONOCOPHILLIPS ALASKA
# ALPINE PIPELINE SYSTEM

U.S. Department of Transportation
Pipeline and Hazardous Materials Safety Administration
Office of Pipeline Safety
1200 New Jersey Ave, SE
Washington, DC 20590

ConocoPhillips Alaska hereby certifies to the Pipeline and Hazardous Materials Safety Administration of the U.S. Department of Transportation that it has identified, and ensured by contract, or other means to be approved by the Pipeline and Hazardous Materials Safety Administration, the availability of private personnel and equipment to respond, to the maximum extent practicable, to a worst case discharge or a substantial threat of such a discharge.

Scott Collins

2/28/2018

Scott Collins or Philip Susen
Superintendent, DOT Pipelines
ConocoPhillips Alaska

Date

## U.S. DOT NCP / ACP CONSISTENCY CERTIFICATION

# ALPINE PIPELINE SYSTEM

ConocoPhillips Alaska hereby certifies to the Pipelines and Hazardous Materials Safety Administration of the U.S. Department of Transportation that it has reviewed the National Contingency Plan (NCP) and applicable area contingency plan (ACP) and found the Oil Discharge Prevention and Contingency Plan for the Alpine Field and Satellites and Alpine Pipeline System to be consistent with them. The NCP/ACP reviewed includes the NCP developed under 40 CFR Part 300 known as *The Alaska Federal and State Preparedness Plan for Response to Oil and Hazardous Substance Discharges and Releases* (Unified Plan), and the *North Slope Subarea Contingency Plan.*

Scott Collins

Scott Collins or Philip Susen
Superintendent, DOT Pipelines
ConocoPhillips Alaska

2/28/2018

Date

# U.S. DEPARTMENT OF TRANSPORTATION INFORMATION SUMMARY

## NAME AND ADDRESS OF OPERATOR

ConocoPhillips Alaska
P.O. Box 100360
Anchorage, AK 99510-0360
Phone: (907) 265-6150 (Security emergency line)

Street Address:
700 G Street
Anchorage, AK 99510-0360

## RESPONSE ZONE DESCRIPTION

The Alpine Pipeline System, located in the North Slope Borough, Alaska, consists of a single response zone containing a product transportation system, consisting of an onshore pipeline. For purposes of this plan, all the pipelines within the Alpine Pipeline System under the jurisdiction of 49 CFR 149 are considered to be one line section and, therefore, in one response zone.

The Alpine pipelines have individual numbered vertical support members (VSMs) that can be used to identify specific line segments, if necessary.

## NAME AND TELEPHONE NUMBER OF QUALIFIED INDIVIDUAL

**Qualified Individual:**

Manager, Western North Slope Operations

Misty Alexa

(907) 670-4024

**Alternate:**

Superintendent, Operations & Maintenance

Mike Lyden/Glynn Jones

(907) 670-4021

COPA Security maintains 24-hour contact numbers for the Qualified Individual and alternates. Security can be reached in Anchorage at (907) 265-6150 or at Alpine at (907) 670-4900.

## BASIS OF DETERMINATION OF SIGNIFICANT AND SUBSTANTIAL HARM

As stated in 49 CFR 194.103(c), a line section can be expected to cause significant and substantial harm to the environment in the event of a discharge of oil into or on the navigable waters or adjoining shorelines if; the pipeline is greater than 6 5⁄8 inches in outside nominal diameter, greater than 10 miles in length, and the line section is located within a 1 mile radius of potentially affected environmentally sensitive areas, and could reasonably be expected to reach these areas.

The crude oil transmission pipeline has a nominal diameter of 14 inches and is 34.2 miles in length. In addition, the pipeline traverses tundra and crosses three rivers, two of which are aboveground and the Colville River crossing, which is the only underground portion of the pipeline.

Line segments are described in ODPCP Table 2-5 and Section 3.1.4.

## TYPE OF OIL AND VOLUME OF WORST CASE DISCHARGE

The type of oil transported in the DOT-regulated pipeline at Alpine is sales quality crude oil. The worst-case discharge (WCD) for Alpine would occur from a rupture of the pipeline between the pig receiver at Kuparuk Central Processing Facility #2 (CPF2) and the vertical loop[1] (#5) nearest CPF2 on the east side of the Miluveach River. The WCD volume includes the entire volume of the pipeline segment between CPF2 and vertical loop #5 in addition to the throughput volume lost during 45 minutes before shutdown.

Weather conditions do not affect the pipeline shutdown time (see calculation below). If the emergency shutdown system fails, manual shutdown valves are located inside at the Alpine Central Facility (CD1) and at CPF2. These facilities are staffed 24 hours a day.

In accordance with 49 CFR 194.105(b)(1), the WCD for the pipeline is equal to the pipeline's maximum release time ($RT_{max}$) in hours, plus the maximum shutdown response time ($ST_{max}$) in hours, multiplied by the maximum flow rate ($F_{max}$) expressed in barrels per hour (bph) (based on maximum daily capacity of the pipeline), plus the largest pipeline drainage volume ($PV_{max}$) after shutdown of the line section(s) in the response zone expressed in barrels (bbl) or:

$$WCD = [(RT_{max} + ST_{max}) * F_{max}] + PV_{max}$$

Where:

| | | |
|---|---|---|
| $RT_{max}$ | = | 0.5 hours (30) |
| $ST_{max}$ | = | 0.25 hours (15 minutes) |
| $F_{max}$ | = | 4,167 bph[2] |
| $PV_{max}$ | = | 9,306 bbl[3] |

Therefore, the DOT WCD is:

$$[(0.5 \text{ hrs} + 0.25 \text{ hrs}) \times 4,167 \text{ bph}] + 9,306 \text{ bbl} = 12,431 \text{ bbl of oil}$$

There is no breakout tank in the Alpine operational area / response zone and therefore no WCD for a breakout tank is provided.

Consideration of the maximum historical discharge for WCD calculations is not applicable.

## RESOURCES TO RESPOND TO A WORST CASE DISCHARGE

Sufficient resources are available to respond to a potential WCD or a threat of such a discharge. The WCD calculations are based on the longest portion of the DOT-regulated pipeline at Alpine, which is located between the pig receiver at CPF2 and the vertical loop #5 on the east side of the Miluveach River (Figure 1-10). This portion of pipeline is within 2 miles of the Kuparuk road system.

Information regarding specific tactics and equipment that would be utilized during a WCD is provided in the Alaska Clean Seas (ACS) Technical Manual, Volume 1, Tactics Descriptions. Off-pad spill response tactics

---

[1] Vertical loops perform the same function as check valves without the hydraulic inefficiencies and maintenance concerns associated with check valves. The loops meet the requirements of 49 CFR 195.

[2] Calculated at 100,000 bbls per day throughput

[3] ID of pipe = 13.376 inches (r = 0.56 foot)
Distance between valve and vertical loop = 54,741 feet
Design Pipe Capacity = 0.17 bbl/linear foot: $PV_{max}$ = (0.17 bbl/lin. ft.)(54,741 ft.) = 9,306 bbls

are also detailed in Scenarios 1 through 3 in Section 1.6.3 of this plan. The scenarios include a pipeline discharge to the Miluveach River.

Section 1.1 of the ODPCP describes immediate response and notification actions, which include notification of ACS. The on-site personnel are the initial responders to spills at Alpine. SRT members will respond promptly upon notification. The estimated response time from discovery of a spill to the deployment of equipment varies depending on the location, pre-planning, logistical support, and available information. This section also contains additional information including seasonal transportation options.

Spill response equipment and supplies are available throughout the North Slope for immediate deployment. Equipment is pre-deployed at the CPFs, along the Kuparuk and Miluveach Rivers, and along the coastline. Spill response and/or pre-staged equipment at CPF1 pad can be rapidly deployed via the Kuparuk road system. Off-road oil spill recovery operations can be conducted by Rolligons, Centaurs®, 6-wheelers, and 4-wheelers available to COPA and ACS, the primary oil spill removal organization (OSRO). Infrastructure and pre-staged equipment along the portion of pipeline subject to a potential WCD is illustrated in the ACS Technical Manual, Volume 2, Map Atlas Sheets 26, 29, 53, and 54. Boom is seasonally pre-deployed at both the Miluveach River and Kalubik Creek, which intersect the portion of pipeline subject to a potential WCD.

Spill-tracking equipment includes fixed wing aircraft equipped with a Forward-Looking Infrared (FLIR) System for aerial surveillance of released oil or temperature anomalies that could be indicative of a pipeline leak. Hand-held sensors are also available.

Waste disposal information is contained in the Alaska Waste Disposal and Reuse Guide (aka the Red Book). Released fluids can be recovered and transferred via vacuum truck, or Rolligon with tanks, to the CPF1 hydrocarbon recycle facility or water recycle facility. Oiled gravel storage is located within the Kuparuk road system at drill site 1H. Temporary lined containment cells can be constructed at other locations.

## CERTIFICATION OF RESPONSE PERSONNEL AND EQUIPMENT

Sufficient response personnel and equipment are available to respond to a WCD or threat of such a discharge. The information is provided in Sections 1.6.3, Spill Response Scenarios; 3.5, Logistical Support; 3.6, Response Equipment; and 3.8, Response Contractor Information.

## PUBLIC AWARENESS

COPA is committed to public safety and environmental protection and maintains a public awareness program for COPA-operated DOT-regulated pipelines, in accordance with DOT regulations. COPA periodically provides information to the public via the Hazardous Liquids Pipeline Guide for Emergency and Public Officials and related summary bulletins; a copy of the summary bulletin is provided on pages A-9 and A-10.

## SAFETY IS OUR TOP PRIORITY

# Important Information about **Pipeline Safety**

**At ConocoPhillips Alaska Inc.**, we are committed to operating our North Slope pipelines safely. We are dedicated to the protection of our employees, the public and the environment within the Alpine, Kuparuk and Oliktok pipeline areas.

We want to enhance the continued safe operations of these pipelines, so we invited you to read this brochure to increase pipeline safety awareness. If you have any questions or concerns please contact us:

Alpine DOT Compliance Specialist .......... (907) 670-4224
Kuparuk DOT Compliance Specialist .......... (907) 659-7574

### NORTH SLOPE TRANSPORTATION PIPELINES

Pipelines remain the safest and most reliable method of transporting energy products from the production location to market and the consumer.

We operate, along with our partners, more than 165 miles of transportation pipelines on the North Slope. The U.S. Department of Transportation, Office of Pipeline Safety, regulates approximately 130 miles of these pipelines. They extend from the Alpine Facilities to the Trans Alaska Pipeline System (see Figure 1).

The Alpine Oil Pipeline transports sales-quality crude oil from the Colville River Unit to the Kuparuk Pipeline at CPF2. The Kuparuk Pipeline transports Colville River Unit, Kuparuk River Unit, Milne Point Unit and ENI sales quality crude to the Trans Alaska Pipeline System, connecting at Pump Station 1. A breakout tank is located at CPF2 to provide relief or storage during periods of pipeline upset, proration or maintenance. The Alpine Arctic Heating Fuel Pipeline transports refined petroleum products and the Alpine Utility Pipeline transports treated seawater from CPF2 to the Alpine Facilities. The Oliktok Pipeline transports natural gas from the Prudhoe Bay Unit to CPF1. The Kuparuk and Oliktok Pipelines parallel the Spine Road for much of its route.

### POTENTIAL HAZARDS

While rare, a leak from a transportation pipeline, depending on what the line is carrying at the time, could create breathing hazards for nearby habitants, start a fire or explosion, damage the environment, or injure plants and animals. A leak resulting in an explosion or a fire, inadvertently triggered by vehicles, equipment, or people, increases the risk of potential damage.

### PREVENTIVE MEASURES

At ConocoPhillips, we are accountable for the safe and efficient operations of our pipelines. We monitor and operate the pipeline systems using state-of-the-art operations control centers, 24 hours a day, 365 days a year. In case of an emergency, our control centers can shut down the pipelines, greatly reducing potential hazards.

Additionally, to ensure pipeline integrity, we implement a variety of programs, procedures, and systems, including:

- Ensuring pipeline design, construction, operation and maintenance adhere to federal, state and local codes, regulations and statutes.
- Enforcing aggressive and proactive maintenance programs, such as pipe inspection programs that utilize state-of-the-art tools.
- Using automated, computer-based, around-the-clock pipeline monitoring.
- Conducting routine air and/or ground surveillance.
- Setting up checkpoints along the pipeline route to enhance security when required.

### PIPELINE SIGNAGE

We've attached signage to the North Slope transmission pipelines to enhance identification of the transportation pipelines and to provide emergency contact information (see Figure 2).

Pipeline signage provides important safety information and it is a *federal crime* for any person to willfully deface, damage, remove, or destroy any pipeline sign or right-of-way marker required by federal law. The penalty for each offense is a fine of up to $5,000, imprisonment for not more than one year, or both.

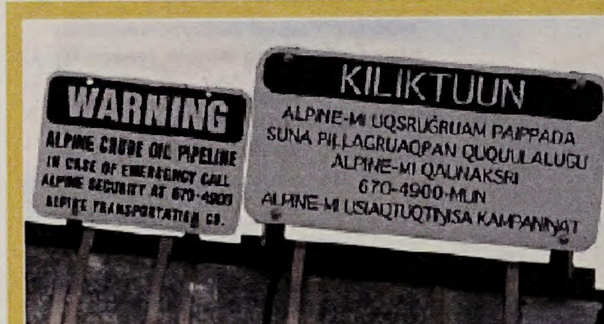



Figure 2 – Example of Pipeline Signage

November 2014

## TO ENSURE YOUR SAFETY

To help ensure your safety and prevent pipeline damage, please ***do not:***

- Operate equipment near pipelines without permission.
- Dig near pipelines without permission.
- Shoot in the direction of the pipelines.
- Climb, walk on, or tie anything to the pipelines.

If you observe any unusual activities taking place near the pipelines, please contact us immediately by the appropriate emergency phone number on the back of this brochure.

## HOW TO RECOGNIZE A LEAK

***By Sight:*** A pipeline product on the ground near a pipeline, a dense white cloud or fog over a pipeline, or discolored vegetation surrounding the pipeline may be signs of a leak.

***By Sound:*** An unusual noise coming from the pipeline, such as hissing or roaring, may be a sign of a leak.

***By Smell:*** An unusual odor may accompany a pipeline leak (e.g., pungent hydrocarbon, kerosene, gasoline-like, etc.).

## IF YOU SUSPECT OR DISCOVER A LEAK

- Do not touch, breathe, or make contact with leaking liquids.
- Do not light a match, start an engine, use a telephone or cell phone, switch on/off light switches, or do anything that may create a spark.
- Do not drive into a leak or vapor cloud area.
- Turn off running motors or other ignition sources.
- Immediately leave the area in an upwind direction.
- Warn others!
- From a safe location, call us as soon as possible by the appropriate emergency phone number listed on the back of this brochure. Please provide your name, phone number, a description of the leak or spill and its location.
- Contact the Nuiqsut Public Safety Department and Fire Department by the emergency phone numbers listed on the back of this brochure.

## WHAT HAPPENS WHEN YOU REPORT A LEAK OR UNUSUAL ACTIVITY

At ConocoPhillips, we take immediate action to stop the leak, contain, and clean up the spill by following approved Discharge Response and Contingency Plans. Our response to reported leaks also includes notifying the appropriate federal, state and local authorities.

We immediately investigate all reported unusual activity near pipelines and take action as appropriate.

## FOR MORE INFORMATION

- **ConocoPhillips Alaska, Inc.**
  P.O. Box 196105
  Anchorage, AK 99519-6105
  (907) 276-1215
- **Pipeline Safety Information**
  http://primis.phmsa.dot.gov/comm/Index.htm
  Website provides stakeholder communications to facilitate pipeline safety.
- **National Pipeline Mapping System**
  http://www.npms.phmsa.dot.gov/

Website provides maps within a specific zip code and information regarding the product transported and identification of the pipeline operator.

Figure 1 – Transportation Pipelines Route

## IN CASE IF EMERGENCY, CALL

**ConocoPhillips Alaska, Inc.**

- Alpine ............ (907) 670-4900 or 911
- Kuparuk ............ (907) 659-7300 or 911

COLLECT CALLS WILL BE ACCEPTED.

**Village of Nuiqsut**

- Public Safety ............ (907) 480-6911
- Fire Department ............ 911

If travelling through the Kuparuk field, you may chose to report leaks or other safety concerns at the Seawater Treatment Plant (STP), CPF2, CPF3, or the Kuparuk Office Complex (KOC).

ConocoPhillips

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 10
222 West 7th Avenue, Room 537, Box 19
Anchorage, Alaska 99513-7588

December 12, 2017

Jeanie Shifflett, Emergency Planning Coordinator
ConocoPhillips Alaska, Inc.
Health, Safety & Environmental
P.O. Box 100360
Anchorage, Alaska 99510-0360

RE: Review of FRPAKA0236, Alpine Field and Satellites and Alpine Pipeline System, Western North Slope, Alaska

Dear Ms. Shifflett:

Pursuant to the Clean Water Act, 33 U.S.C. Section 1321(j)(5), as amended by the Oil Pollution Act of 1990, the United States Environmental Protection Agency (U.S. EPA) has reviewed your Facility Response Plan (FRP) and finds that it meets the requirements of Section 311(j)(5) of the Clean Water Act and 40 CFR 112.20(c)(4). Your FRP is approved for 5 years until December 12, 2022.

Note that, pursuant to 40 CFR 112.20(d)(1), the owner or operator of a facility for which a response plan is required shall revise and resubmit revised portions of the response plan to U.S. EPA within 60 days of each facility change that may materially affect the response to a worst case discharge. Changes which may require revisions to a response plan include:

- a change in the facility's configuration;
- a change in the type of oil handled, stored or transferred;
- a change in the capabilities of the oil spill response organization;
- a change in the facility's spill prevention and response equipment or emergency response procedures; and
- any other change that materially affects the implementation of the response plan.

In addition, 40 CFR Section 112.20(d)(2) provides that changes in personnel and telephone number lists included in an FRP do not require U.S. EPA approval, but should be supplied to U.S. EPA as the revisions occur.

If you have questions regarding this correspondence, please contact me at 907-271-3247 or Vivian Melde at 907-257-5000, ext. 3305.

Sincerely,

Robert S. Whittier, Jr.
On Scene Coordinator (OSC)
Emergency Preparedness and Prevention Unit

**BLANK PAGE**

# U.S. ENVIRONMENTAL PROTECTION AGENCY

## ALPINE FIELD AND SATELLITES
## FACILITY RESPONSE PLAN FRPAKA0236

### CROSS REFERENCE
### [40 CFR 112, APPENDIX F]

| REGULATION SECTION (APPENDIX F) | SECTION TITLE | PLAN SECTION |
|---|---|---|
| **1.1** | **Emergency Response Action Plan [112.20(h)(1)]** | |
| 1.1.1 | Qualified Individual Information | p. A-18 |
| 1.1.2 | Emergency Notification Phone List | Table 1-2 |
| 1.1.3 | Spill Response Notification Form | Figure 1-2 |
| 1.1.4 | Response Equipment List and Location | Section 3.6 |
| 1.1.5 | Response Equipment Testing and Deployment | Sections 1.5 and 3.6.3 |
| 1.1.6 | Facility Response Team | Sections 1.2, 3.3, 3.9 |
| 1.1.7 | Evacuation Plan | Section 1.1 and Introduction Supplemental Documentation |
| 1.1.8 | Immediate Actions | Section 1.1 |
| 1.1.9 | Facility Diagram | Section 1.8 |
| **1.2** | **Facility Information [112.20(h)(2)]** | |
| 1.2.1 | Facility Name and Location | p. A-15 and A-18 |
| 1.2.2 | Latitude and Longitude | p. A-15 and A-18 |
| 1.2.3 | Wellhead Protection Area | Not applicable |
| 1.2.4 | Owner/Operator | p. A-18 |
| 1.2.5 | Qualified Individual | p. A-18 |
| 1.2.6 | Date of Oil Storage Start-up | p. A-18 |
| 1.2.7 | Current Operation | p. A-15, Section 3.1.1 |
| 1.2.8 | Dates and Type of Substantial Expansion | p. A-18 |
| **1.3** | **Emergency Response Information [112.20(h)(3)]** | |
| 1.3.1 | Notification | Sections 1.2 and 3.3 |
| 1.3.2 | Response Equipment List | Section 3.6.1 |
| 1.3.3 | Response Equipment Testing/Deployment | Sections 1.5 and 3.6.3 |
| 1.3.4 | Personnel | Sections 1.5, 3.3, and 3.8 |
| 1.3.5 | Evacuation Plans | Section 1.1 and Introduction Supplemental Documentation |
| 1.3.6 | Qualified Individual's Duties | Section 1.2 and 3.3 |
| **1.4** | **Hazard Evaluation [112.20(h)(4)]** | |
| 1.4.1 | Hazard Identification | Sections 2.1.4, 2.1.6, 2.1.7, 2.1.8, 2.2, 2.3, 2.4, and 2.5; Alpine Spill Prevention, Control, and Countermeasure Plan |
| 1.4.2 | Vulnerability Analysis | Section 3.10 and p. A-19 |
| 1.4.3 | Analysis of the Potential for an Oil Spill | Sections 2.3 and 2.4 |
| 1.4.4 | Facility Reportable Oil Spill History | Section 2.2 and pp. A-25 to A-39 |
| **1.5** | **Discharge Scenarios [112.20(h)(5)]** | |
| 1.5.1 | Small and Medium Discharges | Section 1.6.3 |
| 1.5.2 | Worst Case Discharge | p. A-20, Section 1.6.3 |

## CROSS REFERENCE
## [40 CFR 112, APPENDIX F]

| REGULATION SECTION (APPENDIX F) | SECTION TITLE | PLAN SECTION |
|---|---|---|
| **1.6** | **Discharge Detection Systems [112.20(h)(6)]** | |
| 1.6.1 | Discharge Detection by Personnel | Sections 1.1, 2.1.7, 2.1.8, and 2.5 |
| 1.6.2 | Automated Discharge Detection | Section 2.5 |
| **1.7** | **Plan Implementation [112.20(h)(7)]** | |
| 1.7.1 | Response Resources for Small, Medium and Worst-Case Spills | Sections 1.5, 1.6.3, 3.5, 3.6, 3.7, 3.8, and 3.9 |
| 1.7.2 | Disposal Plans | Sections 1.6.2 and 1.6.3 |
| 1.7.3 | Containment and Drainage Planning | Sections 1.6, 1.8, 2.1.10, and 3.1 |
| **1.8** | **Self Inspection, Drills/Exercises, and Response Training [112.20(h)(8)]** | |
| 1.8.1 | Facility Self-Inspection | Sections 2.1.4, 2.1.7, 2.1.8, 2.1.9, 3.1, 3.6.3, and 3.9.6 |
| 1.8.1.1 | Tank Inspection | Sections 2.1.9 |
| 1.8.1.2 | Response Equipment Inspection | Section 3.6.3 |
| 1.8.1.3 | Secondary Containment Inspection | Section 2.1.10 |
| 1.8.2 | Facility Drills/Exercises | Section 3.9.6 |
| 1.8.2.1 | Qualified Individual Notification Drill Logs | Section 3.9.6 |
| 1.8.2.2 | Spill Management Team Tabletop Exercise Logs | Section 3.9.6 |
| 1.8.3 | Response Training | Section 3.9 |
| **1.9** | **Diagrams [112.20(h)(9)]** | Section 1.8 |
| **1.10** | **Security [112.20(h)(10)]** | Section 2.1.4 |
| **2.0** | **Response Plan Cover Sheet [112.20(h)(11)]** | |
| **2.1** | **General Information** | p. A-15 |
| **2.2** | **Applicability of Substantial Harm Criteria** | p. A-16 |
| **2.3** | **Certification** | p. A-17 |
| **3.0** | **Acronyms** | p. xii |

## U.S. ENVIRONMENTAL PROTECTION AGENCY

## RESPONSE PLAN COVER SHEET



### GENERAL INFORMATION

Owner/Operator of Facility: ConocoPhillips Alaska

Facility Name: Alpine Field and Satellites and Alpine Pipeline System

Facility Address: The Alpine Field and Satellites area is within the Western North Slope of Alaska

(Mailing address) 700 G St., P.O. Box 100360 Anchorage, AK 99510-0360

Facility Phone No.: (907) 276-1215

Latitude (Degrees: North): N 70 degrees, 20 minutes, 40 seconds

Longitude (Degrees: West): W 150 degrees, 55 minutes, 30 seconds

Dun & Bradstreet Number: 118819478

Standard Industrial Classification (SIC) Code: 1330

Largest Above-ground Oil Storage Tank Capacity (Gallons): 138,600

Maximum Oil Storage Capacity (Gallons): 1,346,908

Number of Above-ground Oil Storage Tanks: 732 (stationary bulk storage containers [includes flow-through process vessels], portable bulk storage containers, and oil-filled operational equipment)

Worst Case Oil Discharge Amount (Gallons): 7,566,762

Facility Distance to Navigable Water:
(mark the appropriate distance)

☑ 0-1/4 mile ☐ 1/4-1/2 mile ☐ 1/2-1 mile ☐ >1 mile

## U.S. ENVIRONMENTAL PROTECTION AGENCY

## RESPONSE PLAN COVER SHEET



## APPLICABILITY OF SUBSTANTIAL HARM CRITERIA

Facility Name: Alpine Field and Satellites and Pipeline System.

Does the facility transfer oil over water to or from vessels and does the facility have a total oil storage capacity greater than or equal to 42,000 gallons?

Yes ______

No __X__

Does the facility have a total oil storage capacity greater than or equal to 1 million gallons and does the facility lack secondary containment that is sufficiently large to contain the capacity of the largest above-ground oil storage tank plus sufficient freeboard to allow for precipitation within any above-ground oil storage tank area?

Yes ______

No __X__

Does the facility have a total oil storage capacity greater than or equal to 1 million gallons and is the facility located at a distance (as calculated using the appropriate formula in Appendix C or a comparable formula) such that a discharge from the facility could cause injury to fish and wildlife and sensitive environments?

Yes __X__

No ______

Does the facility have a total oil storage capacity greater than or equal to 1 million gallons and is the facility located at a distance (as calculated using the appropriate formula in Appendix C or a comparable formula) such that a discharge from the facility would shut down a public drinking water intake?

Yes __X__

No ______

Does the facility have a total oil storage capacity greater than or equal to 1 million gallons and has the facility experienced a reportable oil spill in an amount greater than or equal to 10,000 gallons within the last 5 years?

Yes ______

No __X__

## U.S. ENVIRONMENTAL PROTECTION AGENCY

## RESPONSE PLAN COVER SHEET

## PAGE 3 OF 3

## CERTIFICATION

I certify under penalty of law that I have personally examined and am familiar with the information submitted in this document, and that based on my inquiry of those individuals responsible for obtaining information, I believe that the submitted information is true, accurate, and complete.

Signature: Misty Alexa

Name (Please type or print): Misty Alexa

Title: Manager, Western North Slope Operations

Date: March 5, 2018

## U.S. ENVIRONMENTAL PROTECTION AGENCY INFORMATION SUMMARY

## FACILITY INFORMATION

Facility Name: Alpine Field and Satellites and Pipeline System

Location: The Alpine Development Area is located on the Western North Slope of Alaska

City: North Slope Borough

State: Alaska

County: N/A

Phone Number: (907) 670-4900 (Alpine Security)

Latitude: N 70 Degrees, 20 Minutes, 40 Seconds

Longitude: W 150 Degrees, 55 Minutes, 30 Seconds

Wellhead Protection Area: Not applicable

Owner: ConocoPhillips Alaska

Owner Location: 700 G Street, P.O. Box 100360 Anchorage, Alaska 99510-0360 (mailing address)

City: Anchorage

State: Alaska

County: N/A

Phone Number: (907) 276-1215

Operator (if not Owner): ConocoPhillips Alaska

Qualified Individual(s): Misty Alexa

Position Title: Manager, Western North Slope Operations

Work Address: 700 G Street, P.O. Box 100360, Anchorage, AK 99510-0360 OR Alpine CD1

Home Address: Anchorage, Alaska

Emergency Phone Number: (907) 265-1000 (Anchorage Security); (907) 670-4900 (Alpine Security)

Date of Oil Storage Start-up: 1999

Current Operations: Drilling, Production, Processing, and Oil Transfer (pipeline)

Standard Industrial Classification: 1330

Date(s) and Types(s) of Substantial Expansion(s):

Summer 2004 production and seawater facility expansion. Expansion occurred during spring and winter 2005 and 2006, respectively, with the construction and development of drill sites CD3 and CD4. Construction and development of drill site CD5 and in-field flow lines, and construction of a bridge over the Nigliq Channel occurred during winter 2013 and 2014; on-pad facilities were installed in 2015. Construction and development of drill site GMT1 and in-field flow lines, and construction of a gravel pad and road occurred during winter 2017 and 2018; on-pad facilities were installed in 2018.

## VULNERABILITY ANALYSIS

The vulnerability analysis table below identifies the potential effects of an oil discharge as prescribed by 40 CFR 112, Appendix F section 1.4.2.

| VULNERABILITY | ANALYSIS |
|---|---|
| Water intakes | There is a freshwater intake for the Alpine camp and operations at nearby permitted lakes (ACS *Technical Manual*, Volume 2, Map Atlas, Sheet 20). A freshwater drinking water intake for Nuiqsut is located over 8 miles away from the facility. |
| Schools | Schools are present in the city of Nuiqsut, located approximately 8 miles from the facility. Impact to schools is not anticipated. |
| Medical facilities | COPA medical facilities are located at the main camp facilities at CD1. Medical facilities are present in the city of Nuiqsut, located approximately 8 miles from the facility. |
| Residential areas | Nuiqsut is a residential area located approximately 8 miles from the facility. Native allotments and homesteads are in the vicinity of the Alpine area. |
| Businesses | Alpine is neighbored by other oil and gas exploration and production businesses that may or may not be active. |
| Wetlands or other sensitive environments | There are wetlands in the area. Environmentally sensitive areas are discussed in Section 3.10 of the FRP. |
| Fish and Wildlife | The area surrounding the facility provides important habitat for migratory birds, land and marine mammals, anadromous fish, and resident fish. Fish species documented in the area include arctic cisco, chum salmon, dolly varden, least cisco, pink salmon, rainbow smelt, and whitefish. |
| Lakes and streams | The primary rivers in the area include the Colville River, Sakoonang Channel, Nigliq Channel, Nigliagvik Channel, Tinmiaqsiugvik River, and Fish Creek Basin. There are also numerous small lakes, ponds, and streams in the area. |
| Endangered Flora and Fauna | Polar bears, spectacled eiders, and Steller's eiders are listed as *threatened* and managed by US Fish and Wildlife Service (USFWS). Ringed seals are listed as *threatened* and managed by the National Marine Fisheries Service (NMFS). Bowhead, fin, and humpback whales are listed as *endangered* and managed by NMFS; however, fin and humpback whales are rarely in the project area. |
| Recreational areas | The expansive area surrounding Alpine facilities may be utilized by local residents of Nuiqsut for boating, subsistence hunting, and camping. Cabins and fishing camps are present along the channels of Fish Creek. |
| Transportation routes | The Alpine facilities are interconnected by gravel roads or are accessed by airstrip. There is no permanent gravel road connection to Deadhorse. Temporary ice roads may be constructed during winter season to allow transportation from Deadhorse to Alpine and Nuiqsut.<br>A gravel airstrip is maintained at Alpine CD1 and CD3, and in Nuiqsut; the airstrips provide year-round transportation support. |
| Utilities | A natural gas transmission pipeline is present from Alpine CD1 to Nuiqsut. |
| Other Areas of Economic Importance | The expansive area surrounding Alpine facilities is utilized by local residents for subsistence hunting, trapping, and gathering. |

## WORST CASE DISCHARGE

### Type of Oil and Volume of Worst Case Discharge

Using the calculation described in 40 CFR 112, Appendix D, Part B.2, the WCD is equal to the capacity of the largest single aboveground oil storage tank within an adequate secondary containment area, plus the volume of all aboveground tanks without adequate secondary containment, plus the production volume of the well with the highest output.

### Worst -Case Discharge Calculations

- The largest tank has a 3,300-barrel capacity (138,600 gallons). The tank stores diesel for use at the facilities. Produced fluids are not stored in bulk oil storage tanks or tank batteries, they are transferred by flowline directly to a sales oil processing facility.
- The volume of containers without adequate secondary containment is: zero (0) barrels.
- The well with highest output at Alpine is at 10,000 barrels of oil per day (bopd) and is less than 10,000 feet deep, with total vertical depth at 7,380 feet.
- Alpine production facilities are attended (monitored) 24-hours a day, and initial response personnel and equipment are immediately available to respond to a discharge.
- Recovery rate is based on combined liquid recovery capacity, as presented in plan Section 1.6.3, Scenario 1, Table 1-7.
- Production volume of well = discharge volume 1 (DV1) + discharge volume 2 (DV2) (see 40 CFR 112 Appendix D, Attachment D-1, section 2.2 Method B).

**Where:**

DV1 = (days unattended + days to respond) * (rate of well)

= (0 days + 0.17 days) *10,000 bopd = 1,700 bbl (71,400 gallons)

DV2 = [30 days – (days unattended + days to respond)] * (rate of well) * (rate of well/rate of recovery)

= [30 days – (0 days + 0.17 days)] * (10,000 bopd) * (10,000 bopd / 17,030 bopd) = 175,161 bbl (7,356,762 gallons)

Production volume of well = 1,700 bbl + 175,161 bbl = 176,861 bbl (7,428,162 gallons)

**Therefore:**

WCD = 3,300 bbl + 0 bbl + 176,861 bbl = 180,161 bbl (7,566,762 gallons)

## BASIS FOR DETERMINATION OF SIGNIFICANT AND SUBSTANTIAL HARM

Operations at Alpine have potential to spill hydrocarbon material on tundra (wetlands) and into navigable waters of the United States. As such, it is determined to pose significant and substantial harm should a spill occur.

## ATTACHMENT E-1

## WORKSHEET TO PLAN VOLUME OF RESPONSE RESOURCES FOR WORST CASE DISCHARGE – PETROLEUM OILS

## CRUDE OIL WCD

Part I Background Information

Step (A) Calculate Worst Case Discharge in barrels (Appendix D) . . . . . . 176,861 (A)

Step (B) Oil Group[1](Table 3 and section 1.2 of this appendix) . . . . . . . . 2

Step (C) Operating Area (choose one) . . . . ☐ Nearshore/Inland Great Lakes ☒ or Rivers and Canals

Step (D) Percentages of Oil (Table 2 of this appendix)

| Percent Lost to Natural Dissipation | Percent Recovered Floating Oil | Percent Oil Onshore |
|---|---|---|
| 40 | 15 | 45 |
| (D1) | (D2) | (D3) |

Step (E1) On-Water Oil Recovery $\frac{\text{Step (D2) x Step (A)}}{100}$ 26,529 (E1)

Step (E2) Shoreline Recovery $\frac{\text{Step (D3) x Step (A)}}{100}$ 79,587 (E2)

Step (F) Emulsification Factor
(Table 3 of this appendix) . . . . . . . . . . . . . . . . . . . . . . . . . 1.8 (F)

Step (G) On-Water Oil Recovery Resource Mobilization Factor
(Table 4 of this appendix)

| Tier 1 | Tier 2 | Tier 3 |
|---|---|---|
| 0.30 | 0.40 | 0.60 |
| (G1) | (G2) | (G3) |

[1] A facility that handles, stores, or transports multiple groups of oil must do separate calculations for each oil group on site except for those oil groups that constitute 10 percent of less by volume of the total oil storage capacity at the facility. For purposes of this calculation, the volumes of all products in an oil groups must be summed to determine the percentage of the facility's total oil storage capacity.

## ATTACHMENT E-1 (CONTINUED)

## WORKSHEET TO PLAN VOLUME OF RESPONSE RESOURCES

## FOR WORST CASE DISCHARGE – PETROLEUM OILS

## CRUDE OIL WCD

Part II On-Water Oil Recovery Capacity (barrels/day)

| Tier 1 | Tier 2 | Tier 3 |
|---|---|---|
| 14,326 | 19,101 | 28,651 |
| Step (E1) x Step (F) x Step (G1) | Step (E1) x Step (F) x Step (G2) | Step (E1) x Step (F) x Step (G3) |

Part III Shoreline Cleanup Volume (barrels) . . . . . . . . . . . . . . . . . . . . . 143,257

Step (E2) x Step (F)

Part IV On-Water Response Capacity by Operating Area

(Table 5 of this appendix)

(Amount needed to be contracted for in barrels/day)

| Tier 1 | Tier 2 | Tier 3 |
|---|---|---|
| 1,875 | 3,750 | 7,500 |
| (J1) | (J2) | (J3) |

Part V On-Water Amount Needed to be Identified, but not Contracted for in Advance (barrels/day)

| Tier 1 | Tier 2 | Tier 3 |
|---|---|---|
| 12,451 | 15,351 | 21,151 |
| Part II Tier 1 - Step (J1) | Part II Tier 2 - Step (J2) | Part II Tier 3 - Step (J3) |

NOTE: To convert from barrels/day to gallons/day, multiply the quantities in Parts II through V by 42 gallons/barrel.

**ATTACHMENT E-1**

**WORKSHEET TO PLAN VOLUME OF RESPONSE RESOURCES**

**FOR WORST CASE DISCHARGE – PETROLEUM OILS**

**ULTRA-LOW SULFUR DIESEL, TANK CF-T-61001**

Part I Background Information

Step (A) Calculate Worst Case Discharge in barrels (Appendix D) . . . . . . 3,300 (A)

Step (B) Oil Group[1] (Table 3 and section 1.2 of this appendix) . . . . . . . . 1

Step (C) Operating Area (choose one) . . . . ☐ Nearshore/Inland Great Lakes ☒ or Rivers and Canals

Step (D) Percentages of Oil (Table 2 of this appendix)

| Percent Lost to Natural Dissipation | Percent Recovered Floating Oil | Percent Oil Onshore |
|---|---|---|
| 80 | 10 | 10 |
| (D1) | (D2) | (D3) |

Step (E1) On-Water Oil Recovery $\frac{\text{Step (D2) x Step (A)}}{100}$ 330 (E1)

Step (E2) Shoreline Recovery $\frac{\text{Step (D3) x Step (A)}}{100}$ 330 (E2)

Step (F) Emulsification Factor
(Table 3 of this appendix) . . . . . . . . . . . . . . . . . . . . . . . . . . 1.0 (F)

Step (G) On-Water Oil Recovery Resource Mobilization Factor
(Table 4 of this appendix)

| Tier 1 | Tier 2 | Tier 3 |
|---|---|---|
| 0.30 | 0.40 | 0.60 |
| (G1) | (G2) | (G3) |

[1] A facility that handles, stores, or transports multiple groups of oil must do separate calculations for each oil group on site except for those oil groups that constitute 10 percent of less by volume of the total oil storage capacity at the facility. For purposes of this calculation, the volumes of all products in an oil groups must be summed to determine the percentage of the facility's total oil storage capacity.

**ATTACHMENT E-1 (CONTINUED)**

**WORKSHEET TO PLAN VOLUME OF RESPONSE RESOURCES**

**FOR WORST CASE DISCHARGE – PETROLEUM OILS**

**ULTRA-LOW SULFUR DIESEL, TANK CF-T-61001**

Part II On-Water Oil Recovery Capacity (barrels/day)

| Tier 1 | Tier 2 | Tier 3 |
|---|---|---|
| 99 | 132 | 198 |
| Step (E1) x Step (F) x Step (G1) | Step (E1) x Step (F) x Step (G2) | Step (E1) x Step (F) x Step (G3) |

Part III Shoreline Cleanup Volume (barrels) . . . . . . . . . . . . . . . . . . . 330

Step (E2) x Step (F)

Part IV On-Water Response Capacity by Operating Area
(Table 5 of this appendix)
(Amount needed to be contracted for in barrels/day)

| Tier 1 | Tier 2 | Tier 3 |
|---|---|---|
| 1,875 | 3,750 | 7,500 |
| (J1) | (J2) | (J3) |

Part V On-Water Amount Needed to be Identified, but not Contracted for in Advance (barrels/day)

| Tier 1 | Tier 2 | Tier 3 |
|---|---|---|
| -1,776 (0) | -3,618 (0) | -7,302 (0) |
| Part II Tier 1 - Step (J1) | Part II Tier 2 - Step (J2) | Part II Tier 3 - Step (J3) |

NOTE: To convert from barrels/day to gallons/day, multiply the quantities in Parts II through V by 42 gallons/barrel.

## ALPINE OIL SPILLS TO NAVIGABLE WATERS (TUNDRA AND WATER)

| Date of Discharge | Discharge Cause; Spill Source | Material Discharged | Volume Discharged (gal) | Volume to Tundra (gal) | Volume to Water (gal) | Volume to Containment (gal) | Cleanup Actions | Corrective Action | Cause Explanation/ Description of Detection |
|---|---|---|---|---|---|---|---|---|---|
| 1/10/1999 | Cause: Flange Leak/ Failure; Source: Not Specified | Hydraulic Fluid-100% | 2.00 | 1.00 | 0.00 | 0.00 | 100% Recovered; Disposal Location: Snowmelter at B70 Pad | Equipment repaired. | Blown O-ring on joy compressor |
| 1/15/1999 | Cause: Rolling Stock Leak; Source: Not Specified | Hydraulic Fluid-100% | 1.00 | 0.00 | 1.00 | 0.00 | 100% Recovered; Disposal Location: Snowmelter at B70 Pad | Equipment repaired. | Failed O-ring on end dump. |
| 1/25/1999 | Cause: Rolling Stock Leak; Source: Not Specified | Hydraulic Fluid-100% | 0.30 | 0.00 | 0.30 | 0.00 | 100% Recovered; Disposal Location: Snowmelter at B70 Pad | Equipment repaired. | Hydraulic line broke due to extreme temperatures (-40F) |
| 1/27/1999 | Cause: Rolling Stock Leak; Source: Not Specified | Hydraulic Fluid-100% | 4.00 | 0.00 | 3.00 | 1.00 | 100% Recovered; Disposal Location: Snowmelter at B70 Pad | Operations were ceased and equipment repaired. | Hydraulic line on 65-ton hydro-crane snagged on rotor and was stretched. Line did not break but caused leak around seal. |
| 2/22/1999 | Cause: Human Error; Source: Heavy Equip/Mobile Equip/Vehicles | Diesel-100% | 5.00 | 5.00 | 0.00 | 0.00 | 100% Recovered; Disposal Location: Snowmelter at B70 Pad | | Heavy equipment (B70) lost control and veered off road causing fuel tank to rupture. |
| 2/26/1999 | Cause: Rolling Stock Leak; Source: Not Specified | Hydraulic Fluid-100% | 0.10 | 0.00 | 0.10 | 0.00 | 100% Recovered; Disposal Location: Snowmelter at B70 Pad | Patrol area for confirmation of source. Advise personnel to use containment under vehicles and equipment. | Multiple users of lake; positive identification of origin unknown. |
| 2/27/1999 | Cause: Rolling Stock Leak; Source: Heavy Equip/Mobile Equip/Vehicles | Hydraulic Fluid-100% | 20.00 | 20.00 | 0.00 | 0.00 | 100% Recovered; Snow bagged for disposal at snowmelter - gravel taken to DS-1H. | Operator training; monitor equipment movement so valve is protected. | Containment (drip pan), lodged against valve when moving equipment, causing valve to open. |
| 3/3/1999 | Cause: Rolling Stock Leak; Source: Not Specified | Motor Oil-100% | 0.50 | 0.00 | 0.50 | 0.00 | 100% Recovered; Snow bagged for disposal at snowmelter - gravel taken to DS-1H. | Closer inspection of all vehicles visiting the Alpine field. | Unknown, not able to determine cause or equipment user/operator. |
| 3/7/1999 | Cause: Rolling Stock Leak; Source: Heavy Equip/Mobile Equip/Vehicles | Hydraulic Fluid-100% | 35.00 | 35.00 | 0.00 | 0.00 | 98% Recovered | Equipment repaired. | D10N equipment hydraulic line failed |

## ALPINE OIL SPILLS TO NAVIGABLE WATERS (TUNDRA AND WATER), CONTINUED

| Date of Discharge | Discharge Cause; Spill Source | Material Discharged | Volume Discharged (gal) | Volume to Tundra (gal) | Volume to Water (gal) | Volume to Containment (gal) | Cleanup Actions | Corrective Action | Cause Explanation/ Description of Detection |
|---|---|---|---|---|---|---|---|---|---|
| 3/7/1999 | Cause: Rolling Stock Leak; Source: Not Specified | Hydraulic Fluid-100% | 0.80 | 0.00 | 0.80 | 0.00 | 100% Recovered; Disposal Location: Snowmelter at B70 Pad | Equipment repaired. | Failed hydraulic line on ballderson hitch. |
| 3/8/1999 | Cause: Rolling Stock Leak; Source: Heavy Equip/Mobile Equip/Vehicles | Hydraulic Fluid-100% | 3.00 | 2.80 | 0.00 | 0.00 | 100% Recovered; Disposal Location: Snowmelter at B70 Pad | Tighten connection, check occasionally by maintenance crew. | Hose connection loose, parted from connection. |
| 3/14/1999 | Cause: Rolling Stock Leak; Source: Heavy Equip/Mobile Equip/Vehicles | Diesel-100% | 2.00 | 2.00 | 0.00 | 0.00 | 100% Recovered; Disposal Location: Snowmelter at B70 Pad | Replaced damaged line. | Euclid B-70 went off road and compromised the fuel line. |
| 3/29/1999 | Cause: Equipment Difficulty; Source: Heavy Equip/Mobile Equip/Vehicles | Hydraulic Fluid-100% | 0.10 | 0.00 | 0.10 | 0.00 | 100% Recovered; Disposal Location: Snowmelter at B70 Pad | Loader taken out of service for repair. | Hose leak on loader. |
| 4/5/1999 | Cause: Human Engineering; Source: Heavy Equip/Mobile Equip/Vehicles | Glycol-67%, Motor Oil-33% | 2.00 | 0.00 | 2.00 | 0.00 | 100% Recovered; Disposal Location: Snowmelter at B70 Pad | Discussed accident cause and events in craft safety meetings. | Cement Truck #76003 lost control on ice road and left the roadway. |
| 5/4/1999 | Procedures; Source: Heavy Equip/Mobile Equip/Vehicles | Diesel-98%, Glycoll-1%, Motor Oil-1% | 252.00 | 252.00 | 0.00 | 0.00 | 100% Recovered; contaminated snow taken to snow melter. | Reduce speed during warm weather. | Traveling too fast for road condition. |
| 6/10/1999 | Training; Source: Drums/Containers/ Dumpsters | Diesel-100% | 10.00 | 10.00 | 0.00 | 0.00 | 100% Recovered; Disposal Location: DS-1H Pit; Liquids recycled. | Immediate action to contain sheen using boom and absorb (dumpster storage procedures). | Sheen was found off pad, probable cause was dumpster storage during winter on pad. |
| 6/16/1999 | Cause: Human Engineering; Source: Transfer Hoses | Diesel-100% | 2.00 | 1.00 | 1.00 | 0.00 | 100% Recovered; Sorbant taken to incinerator | - | Diesel spill in snow sometime during winter construction. |
| 1/7/2000 | Cause: Equipment Difficulty; Source: Heavy Equip/Mobile Equip/Vehicles | Hydraulic Fluid-100% | 0.10 | 0.00 | 0.10 | 0.00 | 100% Recovered; Staged in containment cell for disposal at 1H. | Replaced seal. | Balerson hitch pin actuator seal failure. Equip. # 42-025 |

| Date of Discharge | Discharge Cause; Spill Source | Material Discharged | Volume Discharged (gal) | Volume to Tundra (gal) | Volume to Water (gal) | Volume to Containment (gal) | Cleanup Actions | Corrective Action | Cause Explanation/ Description of Detection |
|---|---|---|---|---|---|---|---|---|---|
| 1/24/2000 | Cause: Equipment Difficulty; Source: Fittings/Seals/Connections | Hydraulic Fluid-100% | 0.30 | 0.00 | 0.30 | 0.00 | 100% Recovered; Contaminated ice chipped and placed in bags. Transported to ACS holding area pending snow melting. | - | Hydraulic brake line failure on DJB. |
| 2/27/2000 | Cause: Unknown; Source: Heavy Equip/Mobile Equip/Vehicles | Motor Oil-100% | 0.30 | 0.00 | 0.30 | 0.00 | 100% Recovered; Disposal Location: Snowmelter | Continue to review policies and procedures in tool box and weekly safety meetings about spill prevention and reporting. Also the need for better maintenance of equipment. | Unknown |
| 3/4/2000 | Cause: Equipment Difficulty; Source: Heavy Equip/Mobile Equip/Vehicles | Hydraulic Fluid-100% | 4.50 | 0.00 | 4.50 | 0.00 | 100% Recovered; ACS storage cell - waiting for snowmelter | Replaced new hose. | Failed hydraulic hose on Challenger equipment #AH8023. |
| 3/15/2000 | Cause: Equipment Difficulty; Source: Heavy Equip/Mobile Equip/Vehicles | Hydraulic Fluid-100% | 5.00 | 5.00 | 0.00 | 0.00 | 100% Recovered; Disposal Location: Snowmelter | Replaced with new O-ring. | An O-ring on transmission filter failed. |
| 3/23/2000 | Cause: Equipment Difficulty; Source: Flares | Diesel-100% | 9.00 | 9.00 | 0.00 | 0.00 | 100% Recovered; Disposal Location: DS-1H Pit | Replaced fuel filter. | O-ring failed on fuel filter. |
| 4/20/2000 | Cause: Equipment Difficulty; Source: Heavy Equip/Mobile Equip/Vehicles | Diesel-100% | 0.50 | 0.50 | 0.00 | 0.00 | 100% Recovered; Disposal Location: Snowmelter | Isolated reserve tank. | Reserve fuel tank pressurized spilling diesel out of filler cap. |
| 5/9/2000 | Cause: Equipment Difficulty; Source: Fittings/Seals/Connections | Hydraulic Fluid-100% | 0.30 | 0.00 | 0.30 | 0.00 | 100% Recovered; Disposal Location: Snowmelter | Equipment moved to shop and repaired. | Hydraulic line failure. |
| 9/4/2000 | Cause: Equipment Difficulty; Source: Tanks | Hydraulic Fluid-100% | 0.10 | 0.10 | 0.00 | 0.00 | 100% Recovered; Disposal Location: Oily Waste | Tighten hydraulic fluid cap. | Hydraulic fluid cap leaked while equipment was on an incline. |

## ALPINE OIL SPILLS TO NAVIGABLE WATERS (TUNDRA AND WATER), CONTINUED

| Date of Discharge | Discharge Cause; Spill Source | Material Discharged | Volume Discharged (gal) | Volume to Tundra (gal) | Volume to Water (gal) | Volume to Containment (gal) | Cleanup Actions | Corrective Action | Cause Explanation/ Description of Detection |
|---|---|---|---|---|---|---|---|---|---|
| 9/18/2000 | Cause: Equipment Difficulty; Source: Heavy Equip/Mobile Equip/Vehicles | Hydraulic Fluid-100% | 0.10 | 0.10 | 0.00 | 0.00 | 100% Recovered; Absorb was incinerated at Alpine. | Hose was replaced. | Hose Failure |
| 11/4/2000 | Cause: Equipment Difficulty; Source: Fittings/Seals/Connections | Diesel-100% | 0.20 | 0.20 | 0.00 | 0.00 | 100% Recovered; ACS Drum Dock awaiting Snow Melter. | Teflon tape was added to the plug's threads. | Fuel tank plug leaked. |
| 12/8/2000 | Cause: Human Engineering; Source: Heavy Equip/Mobile Equip/Vehicles | Diesel-1%, Hydraulic Fluid-99% | 0.30 | 0.00 | 0.30 | 0.00 | 95% Recovered; Taken to Prudhoe Bay to Catco Base Camp. | Residual impacted area (sheen) will be allowed to freeze and frozen impacted area removed at a later date using a chain saw. | Front right side of Rolligon broke through the ice. |
| 3/11/2002 | Cause: Equipment Difficulty; Source: Fittings/Seals/Connections | Crude-1%, Diesel-30%, Freshwater-64%, Produced water-5%) | 15.00 | 0.00 | 0.00 | 10.00 | 90% Recovered; CD1-19a Class II disposal well for melted snow, CD1 Class II solids pit for contaminated gravel | | Chicksan swivel joint failed leaking fluid onto the gravel pad. |
| 6/6/2002 | Cause: Equipment Difficulty; Source: Heavy Equip/Mobile Equip/Vehicles | Hydraulic Fluid-100% | 1.00 | 0.70 | 0.00 | 0.30 | 100% Recovered; The contaminated snow was taken to the ACS Hopper. After the snow is melted it will be injected down the Class 1 well WD-2. Based on MSDS/user knowledge, the hydraulic oil is non-hazardous. | The Challenger is on a regular preventative maintenance schedule. The information of this spill event will be provided to the mechanics, to determine if the preventative maintenance for the Challenger needs to be modified. | Hydraulic hose leaked on the Challenger while working on the snow next to the gravel pad. |

| Date of Discharge | Discharge Cause; Spill Source | Material Discharged | Volume Discharged (gal) | Volume to Tundra (gal) | Volume to Water (gal) | Volume to Containment (gal) | Cleanup Actions | Corrective Action | Cause Explanation/ Description of Detection |
|---|---|---|---|---|---|---|---|---|---|
| 3/14/2003 | Cause: Equipment Difficulty; Source: Heavy Equip/Mobile Equip/ Vehicles | Diesel-100% | 0.20 | 0.20 | 0.00 | 0.00 | 100% Recovered; Disposal Location: WD-2 Alpine Class I Disposal | 1. Review availability of different tank designs. Contact manufacturer to obtain appropriate tankage for our use. 2. Revise training to include discussion of increased spill potential when parking/traveling on uneven terrain and additional gravity-feed spill potential from saddle tanks. | Material dripped from the fuel cap of a Sno-cat tucker when the unit was parked on an uneven tundra location due to an inadequate fuel tank system design. |
| 2/19/2004 | Contractor - Nanuq Inc.; Transmission line failure on pickup truck #115 | 100% Transimission Fluid | 0.30 | 0.00 | 0.30 | 0.00 | Chipped and bagged material; brought to AIC snowmelter in Deadhorse. | Check transmission, repair line and perform any necessary maintenance on vehicle prior to placing back in service. | Equipment difficulty. Spill to frozen surface of lake M0025. Ambient air temperature near -50F @ nuiqsut. |
| 3/14/2005 | Contractor - AES PP&C; Equipment Difficulty | 100% Hydraulic Fluid | 1.50 | 0.00 | 1.50 | 0.00 | ACS was contacted. Contaminated snow was collected and trucked to KRU snow melter for further remediation and hydrocarbon recycle. Ice surface was scratched and swept clean. Sent to KRU snow melter - hydrocarbon recycle. | Tap root investigation conducted. | Hydraulic line connection from a loader's snow blower attachment became loose, allowing hydraulic oil to leak onto frozen lake surface. |
| 4/13/2005 | Contractor - AES PP&C; Equipment Difficulty | 10% Motor Oil; 90% Glycol | 6.00 | 0.00 | 0.50 | 5.50 | ACS and environmental responded to the spill. Spill was cleaned up with liners, absorbents, shovels, and ice chippers. Sent to alpine disposal well WD-02. | Preventative maintenance needs improvement as per taproot investigation. | A broken heater hose on a panel truck caused a 6 gallon spill of glycol and motor oil. CD3 pipeline crossing. |
| 4/18/2005 | Contractor - AES PP&C; Equipment Difficulty | 100% Diesel | 0.50 | 0.00 | 0.50 | 0.00 | Impacted river ice was chipped up. Melted in acs snow hopper. Hydrocarbons will be skimmed off and the water sent to WD-02. | None | Spill occurred on the river ice at the CD3 pipeline crossing of the Ulamnigiaq River and appears to have been caused by a leak in the thaw unit's fuel line. |

# ALPINE OIL SPILLS TO NAVIGABLE WATERS (TUNDRA AND WATER), CONTINUED

| Date of Discharge | Discharge Cause; Spill Source | Material Discharged | Volume Discharged (gal) | Volume to Tundra (gal) | Volume to Water (gal) | Volume to Containment (gal) | Cleanup Actions | Corrective Action | Cause Explanation/ Description of Detection |
|---|---|---|---|---|---|---|---|---|---|
| 4/23/2005 | Contractor - AES PP&C; Equipment Difficulty | 100% Motor Oil | 0.10 | 0.00 | 0.10 | Some | Impacted ice was chipped up and collected. Impacted ice will be melted, then the hydrocarbons will be skimmed off and the water sent to WD-2. | Welding unit was taken out of service and sent and sent in for repairs. | Leaking gasket on welding-unit engine. Approximately 1 pint leaked from the welding unit with about 75% caught in the secondary containment under the unit. Approximately 4 ounces of motor oil leaked onto the river ice surface. |
| 5/30/2005 | Cause: Flange Leak/ Failure; Source: Fittings/Seals/Connections | Diesel-100% | 3.00 | 0.00 | 0.20 | 1.00 | 100% Recovered; Contaminated gravel was taken to the Class I gravel cell for further remediation. Liquid and sheen was collected with sorbents and boom and sent to incineration. | Replace fuel line hoses on pump with diesel rated hoses. Verify that hoses on other pumps are diesel rated and discuss with mechanics regarding future PMs on this equipment. | A water pump was being used to dewater an impoundment filled with melting snow directly adjacent to the Alpine CD1 apron area. An improper fuel line was used on the ACS water pump causing diesel fuel to leak into secondary containment, onto the gravel pad and into the water filled impoundment area. |
| 7/27/2005 | Cause: Management System; Source: Heavy Equip/Mobile Equip/Vehicles | Hydraulic Fluid-90%, Motor Oil-10% | 10.50 | 0.30 | 0.00 | 0.00 | 100% Recovered; Disposal Location: WD-2 Alpine Class I Disposal; Small amount of snow/gravel placed into Class I temporary pit. Fluids will be manifested to WD-02 Class I Well. As of 8/6/05, 25 barrels of fluid recovered. | AES will modify periodic skills re-assessment criteria for heavy equipment operators. | Backhoe tipped over due to a slick working area on a slope. |
| 1/28/2006 | Contractor - AES PP&C; Equipment Difficulty | 100% Hydraulic Fluid | 0.50 | 0.00 | 0.50 | 0.00 | ACS responded and chipped up contaminated snow and ice. Contaminated snow and ice sent to snow melter for hydrocarbon recycle. | Taproot investigation. | Hydraulic hose on all terrain dump truck failed while traveling on Sakoonang River ice road crossing. On ice road crossing Sakoonang River. |

| Date of Discharge | Discharge Cause; Spill Source | Material Discharged | Volume Discharged (gal) | Volume to Tundra (gal) | Volume to Water (gal) | Volume to Containment (gal) | Cleanup Actions | Corrective Action | Cause Explanation/ Description of Detection |
|---|---|---|---|---|---|---|---|---|---|
| 2/26/2006 | Contractor - AES PP&C; Equipment Difficulty | 100% Motor Oil | 0.50 | 0.00 | 0.20 | 0.00 | ACS and contractor responded. Used loader and shovels to clean up contaminated snow/ice. Snow was melted in ACS hoppers and sent to WD-02 for Class I disposal. | Investigation and corrective actions. | Spill occurred along the CD3 pipeline ice road and within the Tamayak River crossing (crossing #4). A swalling CCI Kenworth tractor had a belly containment filled with snow/ice during a storm. As the engine was warmed, some of the snow/ice in the containment melted along with motor oil which had leaked into the containment. The tractor was moved from the south side of the Tamayak River crossing (#4) to the north side tracking a 3" to 6" track of motor oil along the ice road and within the Tamayak River crossing. |
| 3/15/2006 | Cause: Unknown; Source: Heavy Equip/Mobile Equip/Vehicles | Hydraulic Fluid-100% | 1.00 | 0.00 | 0.10 | 0.00 | 100% Recovered; Disposal Locations: WD-2 Alpine Class I Disposal; The contaminated snow/ice was bagged and sent to ACS snow melter. Liquid sent to Class I disposal well. | None. | Leaking mobile vehicle. |
| 6/22/2007 | Cause: Unknown; Source: Heavy Equip/Mobile Equip/ Vehicles | Motor Oil-100% | 0.10 | 0.00 | 0.10 | 0.00 | 100% Recovered; Disposal Locations: CD1 Class I pit, WD02 Class I well | Spill cause was unknown | Source and cause is unknown but sheen is located near equipment line. |
| 1/19/2008 | Contractor – Nanuq Inc.; Unknown – likely heavy equipment | 100% Motor Oil | 0.10 | 0.00 | 0.10 | 0.00 | Hand tools were used to remove the contaminated snow and ice. | Attempt to identify the leaking vehicle and have it repaired. Contractor was in the process of inspecting their equipment to see if the source could be determined. | 1/2 cup was spilled on the ice covered lake. The source or cause of the spill is unknown. |

## ALPINE OIL SPILLS TO NAVIGABLE WATERS (TUNDRA AND WATER), CONTINUED

| Date of Discharge | Discharge Cause; Spill Source | Material Discharged | Volume Discharged (gal) | Volume to Tundra (gal) | Volume to Water (gal) | Volume to Containment (gal) | Cleanup Actions | Corrective Action | Cause Explanation/ Description of Detection |
|---|---|---|---|---|---|---|---|---|---|
| 1/20/2008 | Unknown – likely heavy equipment. | 100% Hydraulic Fluid | 0.20 | 0.00 | 0.20 | 0.00 | Hand tools were used to clean up the contaminated ice and snow. | Contractors who used the site were contacted and asked to check their equipment for hydraulic leaks. | Unable to determine cause of spill or the responsible party as the site was used by multiple contractors for water withdraws and no vehicles were at the site at the time of the discovery. |
| 4/4/2008 | Operator error - Heavy Equipment | 100% Diesel | 5.00 | 1.00 | 0.00 | 4.00 | ACS responded and used sorbents and hand tools to clean up the spill. Approval given by ADEC to weed burn and cover area with snow. Weed burned and area covered on 4/5. | Reinspect area in summer. Re-inspected on 7/23/08 and no damage or hydrocarbon staining was evident. 1. Conduct training on recognizing changing conditions that exacerbate ice road driving hazards. Emphasize the need to drive per the conditions being ever mindful of changes. In addition always comply with general safe driving practices. 2. Review, evaluate and recommend safe operational speeds for the hagglunds and document the decisions in the qualification training. 3. Purchase lifesaver hammer to assist in self extrication in the hagglunds. 4. Review the seat belt policy with all employees for use in all vehicles and any deviation from safety policies requires a signed safety variance. | Hagglund vehicle traveling on ice road hit a slick spot and went off of the road, turning onto its side in the process. 4 gallons caught in secondary containment and 1 gallon spilled to snow covered tundra. |

| Date of Discharge | Discharge Cause; Spill Source | Material Discharged | Volume Discharged (gal) | Volume to Tundra (gal) | Volume to Water (gal) | Volume to Containment (gal) | Cleanup Actions | Corrective Action | Cause Explanation/ Description of Detection |
|---|---|---|---|---|---|---|---|---|---|
| 9/12/2008 | Human/Operator error | 100% Motor Oil | 0.70 | 0.70 | 0.00 | 0.00 | Absorbent pads were use to remove as much ponded oil as possible, a vacuum truck was used to remove any oil and water that had ponded under the imprint of the truck, and any residual oil left on the vegetation was burned with permission from ADF&G. | A safe driving bulletin will be put out and addressed with the crews | Employee was driving a pickup truck when the employee lost control and drove on the shoulder of the road which is angled and composed of soft gravel. The employee was trying to avoid a parka squirrel which was in the road. The employee hit a steel culvert and rolled the truck over onto its side. While on its side motor oil leaked out of the engine. |

| Date of Discharge | Discharge Cause; Spill Source | Material Discharged | Volume Discharged (gal) | Volume to Tundra (gal) | Volume to Water (gal) | Volume to Containment (gal) | Cleanup Actions | Corrective Action | Cause Explanation/ Description of Detection |
|---|---|---|---|---|---|---|---|---|---|
| 12/20/2009 | Equipment failure; CD2 | 30% Diesel, 70% Crude Oil | 0.78 | 0.50 | 0.00 | 0.00 | Hand tools are being used to brush the top layer of snow off the tundra where the wind carried a fine misting of the product. A loader scooped up the contaminated snow from the pad. | Remedial plans include a site inspection of the area in the spring to ensure no sheens or residue is observed in the area. Tap root investigation done on incident. E-Line crew to produce written procedures or to address the application of hot diesel. The procedures should include a way to keep the lubricator wipers engaged or having the lubricator packed off when the hot oil is being added. E-Line crew will modify their site conditions check list to include a final site inspection downwind of the work taking place. E-Line crew will evaluate the need to use hot oil during a high wind event. E-Line crew will carry heat detecting guns as standard equipment. E-Line crew will carry heat detecting guns as standard equipment. A modification of the wipers will be looked at in which the opening at the top of the wipers be sized down. | The tap root investigation was not able to determine the exact cause but it is believed that the release could have taken place during the application of hot diesel to the well while the lubricator was attached to the well and the lubricator wipers were not engaged. Additionally high winds would have carried the spray off of the pad. |

| Date of Discharge | Discharge Cause; Spill Source | Material Discharged | Volume Discharged (gal) | Volume to Tundra (gal) | Volume to Water (gal) | Volume to Containment (gal) | Cleanup Actions | Corrective Action | Cause Explanation/ Description of Detection |
|---|---|---|---|---|---|---|---|---|---|
| 2/3/2011 | Flange leak/ failure; On lake L9323 next to the Alpine ice road | 100% Diesel | 6.00 | 0.00 | 6.00 | | Used a loader and bucket, a grader, hand shovels, brooms and absorbents to remove contaminated snow and ice. All the absorbents and some contaminated snow/ice were placed into oily waste bags. The remainder of the contaminated snow and ice was hauled off using a maxi haul. | The lake will be inspected during the summer 2011 helicopter inspections of the alpine ice road. The water truck was driven back to the shop to repair the cracked fuel line. | Nanuq's water truck #135 was on the lake and filling up with a load of water for ice road maintenance. The fuel line on Nanuq water truck #135 cracked due to ice buildup around the fitting. |
| 7/4/2011 | Contractor - Alaska Clean Seas; Moored vessel at Alpine Boat Dock | 100% Motor Oil | 0.12 | 0.00 | 0.12 | 0.00 | The area had a slight sheen inside the boomed area only. The area was boomed prior to the incident as per CPAI policy. The area was skimmed and water was pumped from the boat. No sheen has escaped boomed area. | The boat was removed from the water and inspected to find any holes in the hull. Small holes were found on the deck. The holes that were found were filled to prevent recurrence of sinking. After this incident it has been determined that CPAI will remove from service both this boat and the only other boat on site like it, which cannot be removed from the water for inspection. | Human error. Boat sank while moored. The boat had holes in the hull from modification of a console in the engine compartment. The bilge pump evacuated the water from the compartment until the battery powering the pump died, at which point the boat filled with water and sank, and oil from the engine compartment escaped, creating a sheen. Engine compartment flooded, resulting in sheen. Sheen mostly confined within the boast hull (the hull was above the water line). Small amount escaped hull but remained in boomed area. |

| Date of Discharge | Discharge Cause; Spill Source | Material Discharged | Volume Discharged (gal) | Volume to Tundra (gal) | Volume to Water (gal) | Volume to Containment (gal) | Cleanup Actions | Corrective Action | Cause Explanation/ Description of Detection |
|---|---|---|---|---|---|---|---|---|---|
| 1/10/2012 | Hose failure; Nanuq Lake, Approximately 2 miles SSE of CD2 | 100% Diesel | 0.50 | 0.00 | 0.25 | 0.25 | ACS techs. Were dispatched and cleaned the material from the ice surface with hand tools. Both ACS techs. And the KSOP subsistence representative were on site during spill cleanup activities, and both parties verified that all of the product was removed. | Rock truck was fixed on site and then transported back to Nuiqsut for further inspection and cleaning. | Hose clamp on return fuel line came loose on Nanuq Inc. John Deere rock truck. |

| Date of Discharge | Discharge Cause; Spill Source | Material Discharged | Volume Discharged (gal) | Volume to Tundra (gal) | Volume to Water (gal) | Volume to Containment (gal) | Cleanup Actions | Corrective Action | Cause Explanation/ Description of Detection |
|---|---|---|---|---|---|---|---|---|---|
| 4/16/2014 | Human Factor; pumphouse relief hose placed in wrong position over open hole on frozen lake at ASRC Minesite. | 100% MOTOR OIL | 0.10 | 0.00 | 0.10 | 0.00 | SHEEN WAS REMOVED BY SKIMMING THE WATER SURFACE WITH ABSORBANTS. ABSORBANTS WERE PLACED IN OILY WASTE BAGS AND PUT INTO AN OILY WASTE DUMPSTER AT ALPINE. | THE AIR COMPRESSOR RELIEF HOSE WAS ROUTED AWAY FROM THE WATER HOLE INTO A CONTAINMENT SO THAT NO MORE OIL CAN DRIP INTO WATER HOLE. IN THE FUTURE, ALL BREATHER HOSES WILL BE ROUTED AND SECURED TO CATCHMENT BOTTLES WITHIN SECONDARY CONTAINMENT IN THE PUMPHOUSE, AND WILL BE SECURED IN A WAY THAT PREVENTS THEM FROM HANGING OUTSIDE THE SECONDARY CONTAINMENT OR OVER THE OPEN WATER HOLE. PEAK PERFORMS INSPECTIONS ON THE PUMPHOUSES BEFORE, DURING AND AFTER EACH ICE ROAD SEASON TO IDENTIFY MAJOR MAINTENANCE OR UPGRADES/REPLACE MENTS NEEDED AT PUMP HOUSES. CPAI ENVIRONMENTAL WILL PERFORM PRE-SEASON INSPECTIONS ON ALL PEAK PUMP HOUSES PRIOR TO DEPLOYMENT. | AN AIR COMPRESSOR RELIEF HOSE ON A WATER PUMPHOUSE MOTOR DRIPPED A DROP OF MOTOR OIL INTO AN OPEN WATER HOLE OF A FROZEN LAKE BEING USED FOR ICE ROAD CONSTRUCTION WATER WITHDRAWAL. THE RELIEF HOSE WAS INADVERTANTLY PLACED OVER THE OPEN WATER HOLE. THE OIL WAS MOST LIKELY COMING FROM A LEAK IN THE PISTON RINGS AND IS A SIGN OF ENGINE WEAR. SPILL WAS CONFINED TO A SMALL OPEN-WATER AREA AT THE PUMPHOUSE AND WAS CLEANED IMMEDIATELY. NO SHEEN WAS VISIBLE ON THE WATER OR ICE AFTER CLEAN-UP. |

| Date of Discharge | Discharge Cause; Spill Source | Material Discharged | Volume Discharged (gal) | Volume to Tundra (gal) | Volume to Water (gal) | Volume to Containment (gal) | Cleanup Actions | Corrective Action | Cause Explanation/ Description of Detection |
|---|---|---|---|---|---|---|---|---|---|
| 3/28/2015 | Human Factor; overfill fuel tank on ice pad for CD5 | 100% Diesel | 25.00 | 1.00 | 0.00 | 0.00 | ALL MATERIAL WAS CLEANED BY ACS. HAND TOOLS AND JACKHAMMERS WERE USED TO REMOVE ALL ICE AND SNOW FROM THE AREA. WRITTEN APPROVAL TO BURN FREE DIESEL FROM THE TUNDRA SURFACE WAS GRANTED BY ALASKA DEPT. OF ENVIRONMENTAL CONSERVATION - PREVENTION AND EMERGENCY RESPONSE PROGRAM. | THIS SPILL WAS IDENTIFIED BY ACS TECHNICIANS WHILE CONDUCTING INSPECTIONS AT 0625. THE SPILL WAS ORIGINALLY ESTIMATED AT 4 GALLONS, AND ESTIMATIONS INCREASED ACCORDINGLY AS RECOVERY PROGRESSED. AT APPROXIMATELY 1400 THE RECOVERY EFFORTS HAT REACHED THE TUNDRA SURFACE, AND IMMEDIATE NOTIFICATION WAS MADE TO ALL APPROPRIATE. THE LOCATION INSPECTED DURING THE 2015 SUMMER SEASON VIA HELICOPTER; NO FURTHER INFORMATION OR CLEANUP ACTIONS REQUIRED. | SPILL CAUSED BY INATTENTION OF FUELER WHILE CONDUCTING FUELING OPERATIONS. FUELER NEGLIGENCE LEAD TO EXCESSIVE OVERFILLING OF EQUIPMENT. NEGLIGENT OPERATOR REMOVED FROM PROJECT. |

| Date of Discharge | Discharge Cause; Spill Source | Material Discharged | Volume Discharged (gal) | Volume to Tundra (gal) | Volume to Water (gal) | Volume to Containment (gal) | Cleanup Actions | Corrective Action | Cause Explanation/ Description of Detection |
|---|---|---|---|---|---|---|---|---|---|
| 12/13/2016 | Contractor - heavy equipment; building GMT ice road, water truck tipped off road causing oil to leak from engine. | 100% Motor Oil | 0.80 | 0.75 | 0.00 | 0.05 | TRUCK WAS RIGHTED AND EXTRACTED FROM THE TUNDRA, AFTER WATER TANK WAS PUMPED EMPTY. HAND TOOLS WERE USED TO COLLECT ANY AFFECTED SNOW AND ABSORBENT PADS TO REMOVE FLUID FROM SECONDARY CONTAINMENT. OIL DID NOT PENATRATE THE SURFACE OF THE TUNDRA. SECONDARY CONTAINMENT WAS DEPLOYED UNDER ENGINE COMPARTMENT IMMEDIATELY AFTER INCIDENT OCCURED. | CPAI IS IMPLEMENTING A BETTER SPOTTER SYSTEM FOR THE WATER TRUCKS BACKING DOWN THE ROADS DURING OUR CONDITIONAL CONSTRUCTION OF ICE ROADS AND PADS. THE GRADER OPERATOR WILL SERVE AS THE SPOTTER AND HAS THE BEST VANTAGE POINT DURING THE INITIAL CONSTRUCTION AND WILL BE IN CONSTANT RADIO CONTACT WITH THE TRUCK DRIVERS AS THEY PREPARE TO SPREAD WATER AND WHILE SPREADING WATER. | WHILE BUILDING ICE ROAD, A WATER TRUCK SLIPPED SIDEWAYS OFF THE ROAD DUE TO A SLOPE ON THE PARTIALLY CONSTRUCTED ICE ROAD. THE TRUCK TIPPED ONTO ITS SIDE ALLOWING SOME MOTOR OIL TO LEAK OUT OF THE ENGINE. |

**BLANK PAGE**

# U.S. DEPARTMENT OF THE INTERIOR
# BUREAU OF LAND MANAGEMENT

## ALPINE FIELD AND SATELLITES
## CROSS REFERENCE

| BLM GOVERNANCE DOCUMENT | MEASURE | OBJECTIVE | SUMMARY REQUIREMENT | RELEVANT PLAN SECTION |
|---|---|---|---|---|
| 43 CFR Ch. II Subpart 3162<br>§3162.5 Environment and safety. | §3162.5-1(a) | Environmental obligations | The operator shall conduct operations in a manner which protects the mineral resources, other natural resources, and environmental quality. | Entire plan, demonstrated by this table, in its intended capacity to comply with applicable terms and conditions of approval. |
| | §3162.5-1(c) | Spill reporting per NTL-2007-01-Alaska | Report of major undesirable events. | 1.2.2 |
| | §3162.5-1(d) | Contingency plan | When reasonably required by the authorized officer, a contingency plan shall be submitted describing procedures to be implemented to protect life, property, and the environment. | Introduction – Plan Distribution.<br>Entire plan. |
| February 2013 NPR-A IAP ROD | BMP A-3 a. | Minimize Pollution through effective hazardous-materials contingency planning. | Spill response training for local community. | 3.9.4 |
| | BPM A-3 b. | | Annual spill response drill. | 3.9.6 |
| | BPM A-3 c. | | Develop facility contingency plans and participate in North Slope Subarea Contingency Plan for Oil and Hazardous Substances Discharges/Releases development of environmental sensitivity index maps. | entire plan; 3.10 |
| February 2013 NPR-A IAP ROD<br>February 2015 SEIS ROD | SBMP 2 (new subparagraph to BMP A-3) | | Oil spill response equipment must be effective in Arctic conditions and must have mechanisms to prevent freezing and/or de-ice. | 3.4; 3.8 |
| February 2013 NPR-A IAP ROD<br>February 2015 SEIS ROD | SBMP 3 (new subparagraph to BMP A-3) | Minimize pollution by ensuring adequate facility design criteria and system integrity | Equipment used to develop hydrocarbons must be designed in accordance with standard Arctic engineering practices. | 2.1.5; 2.1.6; 2.1.7; 2.1.8; 2.1.9<br>Part 4 Best Available Technology |
| February 2013 NPR-A IAP ROD | BMP A-4 a. | Minimize the impact of contaminants on fish, wildlife, and the environment, including wetlands, marshes and marine waters, as a result of fuel, crude oil, and other liquid chemical spills. Protect subsistence resources and subsistence activities. Protect public health and safety. | Sufficient oil spill cleanup materials shall be stored at all fueling points and vehicle maintenance areas, and shall be carried by field crews. | 1.3.4; 1.5; 1.6.3; 1.7; 2.1.3; 2.1.5; 2.1.9; 2.3; 3.3; 4.3 |
| | BMP A-4 b. | | Fuel and other petroleum products and other liquid chemicals shall be stored in proper containers…and shall be stored within an impermeable lined and diked area or within approved alternate storage containers…capable of containing 110% of the stored volume. | 2.1.6; 2.1.8 |

| BLM GOVERNANCE DOCUMENT | MEASURE | OBJECTIVE | SUMMARY REQUIREMENT | RELEVANT PLAN SECTION |
|---|---|---|---|---|
| | BMP A-4 c. | | Liner material shall be compatible with the stored product and capable of remaining impermeable during typical weather extremes expected throughout the storage period. | 2.1.10 |
| | BMP A-4 d. | | Permanent fueling stations shall be lined or have impermeable protection to prevent fuel migration to the environment from overfills and spills. | 2.1.10 |
| | BMP A-4 e. | | All fuel containers, including barrels and propane tanks, shall be marked with the responsible party's name, product type, and year filled or purchased. | 2.1.9; 3.1.2; Appendix D<br>Propane tanks are not addressed in the ODPCP. |
| | BMP A-4 f. | | Notice of any reportable spill shall be given to the authorized officer as soon as possible, but no later than 24 hours after occurrence. | 1.2 |
| | BMP A-4 g. | | All oil pans ("duck ponds") shall be marked with the responsible party's name. | Markings on duck ponds do not provide spill prevention or preparedness; therefore, it is not addressed in the ODPCP. Existing policies and procedures on proper handling of duck ponds, spill reporting, and handling oiled materials should provide protection against misuse or mishandling of duck ponds. |
| February 2013 NPR-A IAP ROD February 2015 SEIS ROD | SBMP 1 (new subparagraph to BMP A-4) | | Fuel and hazardous material storage containers with a capacity greater than 660 gallons must use impermeable lining and diking capable of containing 110 percent of the containers' capacity. Vinyl liners, with foam dikes and a capacity of 25 gallons, must be placed under all valves or connections to fuel tanks when located outside of secondary containment. | 2.1.9; 2.1.10; Appendix D |

| BLM GOVERNANCE DOCUMENT | MEASURE | OBJECTIVE | SUMMARY REQUIREMENT | RELEVANT PLAN SECTION |
|---|---|---|---|---|
| February 2013 NPR-A IAP ROD February 2015 SEIS ROD | SBMP 4 a. | Under the requirements of 43 CFR 3162.5-1(c) and (d), develop a contingency plan for blowouts, spills, and other undesirable events that addresses equipment and communication with affected residents. Minimize pollution by ensuring effective hazardous materials contingency planning. Establish BLM's role in an actual response scenario on unitized lands and in the ROW corridor. | The appropriate BLM office must be notified of any spills or releases that occur on unitized lands. Thresholds are established under BLM's NTL-2007-01-Alaska for incidents that require immediate notification (e.g., any blowout that occurs; any spill, regardless of volume, to water, tundra, or undisturbed lands; and spills to land greater than 1 barrel for oil). | 1.2 |
| | SBMP 4 b. | | As part of BLM's approval of the initial Plan, COPA will provide a detailed, probabilistic risk assessment for spills, a most likely trajectory for various environmental conditions related to a catastrophic spill, and an assessment which includes pre-staging equipment across the Nigliq Channel. | 1.6; 2.2; 2.3; 2.4; 3.6.2; Part 5 |
| | SBMP 4 c. | | The BLM will be provided with up-to-date copies of the Alpine C-Plan and all amendments to the plan, which BLM will review (with respect to GMT1) on a five-year basis or as otherwise required by the BLM Authorized Officer. The BLM Authorized Officer reserves the right to require changes to the contingency plan to ensure compliance with Federal requirements. | Introduction, "Plan Updating and Renewal" |
| | SBMP 4 d. | | The BLM will require submission of ACS Technical Manual and any updates. (This describes all the tactics used to control, contain, and clean up a spill.) | Introduction, "Plan Supplemental Documentation" |
| | SBMP 4 e. | | If the Unified Plan is enacted, the Federal On-Scene Coordinator (FOSC) is responsible for directing the emergency spill response. On unitized and Federal lands, necessary measures to control and remove pollutants and to extinguish fires are subject to the approval of the BLM Authorized Officer. | 3.3 |
| | SBMP 4 f. | | If there is a spill due to system failure which necessitates an emergency shut-down of equipment or other in-Unit undesirable event as defined by NTL-2007-01-Alaska, BLM will be notified prior to system restart. This will ensure that repair was appropriately and correctly done, and that appropriate investigations into the root cause of the spill will occur. | 1.2 |

| BLM GOVERNANCE DOCUMENT | MEASURE | OBJECTIVE | SUMMARY REQUIREMENT | RELEVANT PLAN SECTION |
|---|---|---|---|---|
| | SBMP 4 g. | | The BLM will require that specific tactics (e.g., boom locations, access locations, staging areas, etc.) be described for drainages (Crea Creek, Barkley Creek and Tinmiaqsiugvik (Ublutuoch) River) in the GMT1 area, while recognizing that actual spill response would be based on conditions of the time of the spill. | 3.6.2 |
| | SBMP 4 h. | | The BLM will require that the Alpine C-Plan be amended with specific facility descriptions for GMT1, including (Section 3.10) specific environmental features and sensitive areas. | 1.8; 3.1; 3.2; 3.4; 3.10 |
| | SBMP 4 i. | | An emergency countermeasure plan must include well capping if technically feasible. | 1.6.3; 1.9; 4.2 |
| | Preparedness Plan Requirement a. | | The BLM will observe and evaluate responder training and response exercises to ascertain response readiness. The permittee will accommodate BLM's observation of training efforts. | 3.9.6 |
| | Preparedness Plan Requirement b. | | If satellite fields developed in the NPR-A become a significant portion of the Alpine Development Area, BLM be will periodically check the availability of immediate incident responders and to monitor training records. | 3.9.6 |
| | Preparedness Plan Requirement c. | | If any pre-deployed boom is identified for the GMT1 area, BLM requires amendment of Alpine C-Plan to show its location. | 3.6.2 |
| | SBMP 5 | Implement leak detection systems for GMT1 facilities. | To the extent practicable, the permittee will provide a specific description of the leak detections systems installed on all lines described in the development plan. The descriptions could be an addendum to the Alpine C-Plan or a stand-alone document. Monitoring would be via remote continual monitoring (e.g., camera or FLIR) of water crossings, or daily on-site visual inspections. The spill prevention section of the Alpine C-Plan must contain criteria to prevent and detect slow leaks. | 2.1.7 |

# APPENDIX B

# ALPINE PROJECT: OIL PIPELINE SPILL ISOLATION STRATEGY

BLANK PAGE

ALPINE

Alpine Development

# Alpine Project: Oil Pipeline Spill Isolation Strategy

Prepared for

ARCO ALASKA, INC.

ALPINE DEVELOPMENT PROJECT

by

Baker

Michael Baker Jr., Inc.
4601 Business Park Blvd., Suite 42
Anchorage, AK 99503

23100-MBJ-RP-005
December 8, 1998

## Contents

# Executive Summary

Alternative options for isolating and minimizing the volume of oil during a contingency spill event are evaluated and compared using the methodology outline by the California State Fire Marshall Report: "Hazardous Liquid Pipeline Risk Assessment." The first option is a conventional valving strategy, and the second utilizes passive pipeline profile changes constructed with vertical loops. Two types of leaks are evaluated: a pinhole leak and a guillotine failure.

The four contributing components to pipeline spillage considered in the evaluation are:

1. Oil spilled during length of time to detection.
2. Oil spilled operator reaction time.
3. Oil spilled during valve closure time and pipeline/fluid decompression.
4. Oil spilled during pipeline draindown.

The pinhole leak case is considered the more likely spill scenario. Two classes of pinhole leaks are analyzed, those with release rates under the leak detection system detection limit and those with release rates over the detection limit. For very small leaks, those under the detection limit, the volume of oil spilled during the length of time to detection, is by far the major contributor to the total potential oil spill volume for both the conventional valve and the vertical loop cases. The second biggest component of spill volume for the pinhole case is oil spilled during valve closure and pipeline/fluid decompression. Compared to remote operated valves (ROVs), the option utilizing vertical pipeline loops is found to be considerably more effective at minimizing the oil spill volume by not trapping line pressure between adjacent valves. It is concluded that the option utilizing vertical loops is more effective overall at minimizing spill volume for the pinhole leak scenario.

The guillotine failure is considered an extremely unlikely scenario. For this case, the last spill component, oil spilled during draindown, is the largest component contributing to total projected spill volume by an order of magnitude over any other component. Compared to manual isolation block valves, vertical loops decrease the projected spill volume by 63% at the Colville River, 98% at the Kachemach River, and 92% at the Miluveach River by effectively blocking oil in "pools" in the pipeline on the opposite side of the loops.

It is concluded that the alternative utilizing vertical loops is considerably more effective in minimizing spill volumes during contingency spill events. Moreover, the additional possibility of oil leakage at the mechanical connections of the valves, traditionally an area of concern and maintenance, is eliminated.

**It is recommended that the vertical pipeline loops alternative be utilized for the Alpine Pipeline.**

## Summary of December 1998 Revision

This report was updated in December 1998 to add a new section that further describes the design criteria for the vertical loops and illustrates how the loops function. This latest version has also been revised to reflect the most recent design refinements. It is now certain that the oil pipeline will be cased under the Colville River and the number and location of the vertical loops has been optimized. Revised diagrams and text have been included. The decision to use vertical loops (and reasoning) did not change.

# 1.0 Introduction

The purpose of this study is to investigate and determine the best strategy to minimize the volume of an oil spill for the contingency condition of a pipeline leak. There are two alternative strategies to be evaluated and compared for their effectiveness in minimizing the oil spill volume during such an event for the pipelines connecting the Alpine Development to the Kuparuk system:

1. **Valve Installation**, i.e. the case where isolation block valves are installed for the Alpine Project oil sales line. This case assumes remotely actuated valves are installed at the inlet and outlet of the pipeline with remotely operated valves (ROVs) on the east and west banks of the Colville River and manual block valves on the east and west banks of the Kachemach and Miluveach Rivers.
2. **Pipeline Profile Changes**, i.e. the case where vertical pipeline loops are installed at strategic locations to naturally limit oil flow. These loops take advantage of the relatively low terrain relief of the North Slope to provide artificial terrain breaks that greatly reduce the size of potential oil spills. (See Figure 1 for representative vertical loop schematic.)

## 1.1 Regulatory Requirements

The isolation strategy is based on the following:

- **Code of Federal Regulations Title 49, Part 195 - Transportation of Hazardous Liquids by Pipeline (CFR 195)** specifies the following requirement for water crossing locations.

  Paragraph 195.260 reads: "Valves: Location. A valve must be installed at each of the following locations: ... (e) On each side of a water crossing that is more than 100 feet wide from high-water mark to high-water mark unless the administrator finds in a particular case that valves are not justified."
- **ASME B31.4, Liquid Transportation Systems for Hydrocarbons, Liquid Petroleum Gas, Anhydrous Ammonia, and Alcohols**, repeats the design requirements of CFR 195 for valve locations at rivers and streams.

  Paragraph 434.15.2 reads: "Mainline Valves (a) Mainline block valves shall be installed on the upstream side of major river crossings and public water supply reservoirs. Either a block or check valve shall be installed on the downstream side of major river crossings and public water supply reservoirs."

There is no other specific mention of design requirements for water crossings in either document. The issue of valve automation or remote actuation is left to the discretion of the operator, as there is no requirement for remotely actuating valves in either CFR 195 or ASME B31.4. In addition, CFR 195 allows consideration of alternative approaches to isolation strategy if it can be found by the administrator that "...valves are not justified." Thus, if it can be shown that valves are not justified and the administrator agrees with these findings, either of the two alternative approaches being considered in this study are in compliance with regulatory requirements.

Additional project criteria to guide isolation block valve strategy include:

- Install valves (automatic, remotely actuated, or manual) where practical to minimize spill volumes.
- Optimize the number of automatic or remotely actuated valves to maximize environmental safeguards.
- Site block valves at the nominal pipeline elevation, 5 feet above grade, outside the flood zone bounded by the high-water marks to allow access if required during floods.
- Utilize pipe elevation changes where practical to provide drainage breaks.

Based on the regulations, there are three river/stream crossings along the pipeline right-of-way (ROW) that require consideration of an isolation strategy based on the aforementioned regulations: the Colville River, Kachemach River, and Miluveach River. The Colville River crossing requires careful consideration due to the length of the crossing and the sensitive environmental issues involved in this area. The Kachemach River and Miluveach River crossings require consideration because they can extend over 100 feet in width during high-water events, although this width extent is forecasted to occur an average of only two days per year for each river.

## 1.2 Valve Installation Option

Remotely actuated valves have been initially proposed at the Colville River crossing for evaluation since they reduce valve closure time. Manually operated block valves have been proposed for installation at the Kachemach and Miluveach River crossings, because the pipeline is aboveground, allowing access for regular pipeline preventative maintenance, early repair, and emergency access. (See Figure 2 for Isolation Block Valve Location Plan).

Small leaks on pipelines are often associated with valves, flanges, and related fittings. Small leaks often cause the largest spills. Valves are a frequent source of leaks since valves usually have several fittings that could potentially leak. In the case of remotely actuated valves, the potential for spills is increased since a valve/actuator could fail closed, potentially causing a fluid hammer condition that could overpressure the line. Another failure scenario, failure to close, while not adding to the risk of a spill, could allow more oil to spill and perhaps jeopardize the integrity of the spill response plan. A substantial portion of the leaks that have occurred in the Kuparuk River field, from both common carrier and unregulated lines, have been at valves and fittings.

## 1.3 Pipeline Profile Change Option

The alternative of placing vertical loops at all required locations in the pipeline in lieu of valve hardware (except those at the pipeline inlet and outlet) was developed in recognition of the relatively low terrain relief of the North Slope and the spill risks associated with valves. These loops would be installed in the pipeline to form a terrace structure that would significantly limit the amount of oil spilled due to draindown effects. (See Figure 3 for Vertical Loop Location Plan). The potential pipeline spill volumes with this design is less than the potential spill volumes associated with the valved pipeline alternative.

Vertical loops perform the same function as check valves without the hydraulic inefficiencies and maintenance concerns associated with check valves. The long radius bends used to construct vertical loops are the same as those used in standard expansion loops and are considered equivalent to straight pipe. The loops meet the requirements of CFR 195. (See Figure 4 for Vertical Loop Location Profile)

Inclusion of vertical pipeline loops for isolation in the pipeline design provides several advantages besides reducing the risk of spills and limiting the size of spills. The loops do not require maintenance and testing as do block valves. This results in elimination of gravel heliports on the tundra and reduces tundra access requirements. In addition, vertical loops provide crossing points for the north-south movement of caribou near the streams and other points along the pipeline ROW. The upper run of the vertical loops will range between 15 and 45 feet off the ground, providing substantial clearance. The pipeline crossing points provided by the loops can also be used by individuals from the nearby village of Nuiqsut for subsistence activity access.

## 2.0 Pipeline Description

The sales oil pipeline is routed primarily aboveground on vertical support members (VSMs). It is underground at only one location, the Colville River crossing. The pipeline is fabricated using 14-inch diameter high strength line pipe. The pipe in the aboveground portion is uncoated steel pipe, insulated with polyurethane protected by a metal jacket.

The belowground portion at the Colville River crossing is installed by horizontal directional drilling (HDD) inside a high strength casing pipe. Both the casing and carrier pipe at this location are externally coated. Protection against corrosion of the belowground oil pipeline is provided by the external coating and the casing pipe. The casing pipe is protected against corrosion by the external coating and a cathodic protection system Addition of a casing pipe in the HDD design complements the vertical loop effectiveness in reducing the amount of oil spilled. The casing addresses the concerns of leak detection and leak containment under the river.

Actuated pipeline inlet and outlet block valves are incorporated in both the base case and the vertical loop case. These valves would be closed in the event of an emergency such as a spill. Emergency pressure relief valves at each end of the pipeline would be opened to drop the pressure in the pipeline in the event of a spill. These valves play a significant role in reducing the volume of oil leaked during a spill. These valves will be located at facilities where routine inspections and maintenance can detect and minimize leaks. If leaks should occur at these valves, they will be contained on gravel pads or within buildings.

The 39°API gravity crude oil transported by the pipeline is fairly light compared to most other North Slope crude oils. However, it has a paraffin content that starts to precipitate (wax point) at approximately 89°F. The 3-inch pipeline insulation layer along with the 100°F minimum operating temperature of the pipeline accommodates the crude oil wax point plus a safety factor. The additional pipeline height in the vertical loops does not add to the potential cooling, waxing or freezing of the pipeline.

Vertical loops are viewed the same as the standard expansion loops and straight pipe with respect to thermal effects. There is no measurable increase in heat loss due to the increased elevation of the vertical loops. Heat loss along the entire pipeline and its effects on pipeline startup, operation and shutdown, are being addressed as part of the detailed engineering design. This will determine the allowable pipeline shutdown duration limits.

# 3.0 Vertical Loop Operation and Design Description

The alternative of placing vertical loops in the pipeline in lieu of valves, except those at the pipeline inlet and outlet, was developed in recognition of the relatively low relief terrain of the North Slope and the spill risks associated with valves. The proposed loops form a terrace structure to limit the amount of oil spilled due to draindown effects. Vertical loops are essentially hat configuration expansion loops with the outboard run elevated to a pre-determined elevation to limit pipeline draindown caused by an elevation difference.

The vertical loops work by creating hydraulic break points in the pipeline where the fluid in the pipeline will be contained between the loops and other high points along the route, performing a function similar to valves but without the hydraulic inefficiencies and maintenance concerns. The operating effectiveness of the loops is primarily dependent on inlet and outlet block valves that are closed when a leak is detected. The pipeline inlet and outlet block valves create a closed system with no way for a siphon to develop.

A vertical overlap from one loop to another encourages vapor space formation primarily in the vertical and horizontal runs of the loops and not in the long runs of the pipeline between the loops. Some vapor spaces (small discrete bubbles) will form in the horizontal runs but they have little effect on the system. Both bench scale testing and computer simulation indicates that formation of vapor spaces within the vertical loops will stop flow and trap the volume of liquid in the horizontal runs between the loops.

The height of the vertical loops in a pipeline system is a function of the pipeline right-of-way terrain profile. An optimal solution would incorporate loops of varying heights based on the location of the rivers, hills, and other geographic features. In addition, vertical loop siting does not have to take into account access for maintenance activities since they do not require maintenance. They can be optimally sited to minimize spill volumes.

In the field, it is anticipated that during a leak event, the pipeline will be shut down and the inlet and outlet block valves at the ends of the pipeline will be closed. At the same time, the divert valves will open long enough to depressurize the pipeline and drain the line pack into tanks at the inlet and outlet facilities. When the pipeline is depressurized, the divert valves will close. During a depressurization event, the single-phase fluids become multi-phase and vapor spaces will begin forming at the high points.

At this time, the net flow is toward the leak. However, the oil at the highest point in the pipeline will quickly reach its bubble point or vapor pressure and flash, forming a vapor space. The free liquid surface in the downhill side of the vertical loop drops as the line drains. When the liquid level in the highest loop drops to the elevation of the next highest loop the oil in that loop will flash, again forming a vapor space. The oil between the two vapor spaces is effectively isolated from the rest of the pipeline and from the leak. This mechanism will continue the length of the pipeline from vertical loop to vertical loop all the way to the leak site. The estimated volume of oil that could spill is the amount contained between the loops on each side of the leak plus a small amount of the oil in the vertical loops.

Figure 4a-f illustrates the operation of vertical loops. See Figure 5 for the Vertical Loop Location Profile proposed for the Alpine Pipeline. The loops in final design are expected to range from 15' to 45' aboveground, and at a minimum, will be placed on each side of major river crossings (that are greater than 100 feet wide) to comply with US DOT requirements. Figure 5a-c illustrates where liquid would be retained in the system in case of a leak at the Colville, Kachemach, and Miluveach Rivers, respectively.

# 4.0 Pipeline Leak Scenarios

This report conservatively assumes that any pipeline failure mechanisms would result in either:

- A pinhole leak below the detection limit, or
- A pinhole leak above the detection limit, or
- A guillotine failure.

The pinhole leak represents the maximum risk from a difficulty of detection. The guillotine failure represents the maximum spill volume per unit time. The evaluation and comparison of both options spans the range of risk for the pipeline. Both cases are investigated and compared for the alternative spill isolation strategies in this study.

Pinhole leaks can range in size from a true pinhole, perhaps caused by weld porosity or corrosion pitting, to a cracked weld or leaking valve fitting. As the name implies, this type of leak is often very small and usually very difficult to detect. Consequently, they can exist until the threshold of the leak detection system is crossed or they are visually discovered. This can result in oil releases significantly greater than for any other type of leak.

Guillotine cuts, visualized as the complete severing of a pipeline, can result in fairly large volumes of oil spilled. This type of leak can be caused by human activity such as construction accidents, pipe rupture due to overpressure, pipe failure due to defects in the material, or earth movement due to seismic events.

The potential for failure due to human activity is extremely low since the pipeline is routed cross-country and not adjacent to any roads or worksites. The risk of failure due to overpressure is also very low due to redundancy of the overpressure protection systems, as well as the design safety factors incorporated into the material and structural design. Pressure surges are the likely source of overpressure and they have been accounted for in the design of the line and the various support systems. Pipe failure due to defects in the material requires that a manufacturing or construction defect occur simultaneously with high pipe stress. Hydrotesting identifies these flaws since maximum operating stresses are less than the hydrotest stresses.

The final possible cause of a guillotine failure, seismic effects on the pipeline, are considered inconsequential since this is a UBC Seismic Zone 0, coincident with the lowest seismic zone for TAPS. As such, the expected seismic acceleration is 0.05g, resulting in less loading on the pipeline than that caused by the wind.

While the probability of catastrophic failure is remote, the nature of catastrophic pipeline failures causes them to be quickly detected by the leak detection system.

# 5.0 Spill Volume Determination

In the event of a pipeline failure, the amount of oil spilled is the sum of several components. This report uses component descriptions similar to those given in the California State Fire Marshall Report "Hazardous Liquid Pipeline Risk Assessment." They are as follows:

- Length of time to detection,
- Operator reaction time,
- Valve close time and pipeline/fluid decompression, and
- Pipeline drainage.

The major contributor to the volume of oil spilled due to a catastrophic pipeline failure is the pipeline depressuring and pipeline drainage. Due to the nature of the failure, the volume spilled during the time to detection would be relatively small. On the other hand, the major contributor to the volume of oil spilled due to a pinhole leak is the length of time to detection, since the very low leak rates can be lower than the detection threshold of the leak detection system.

The potential leak scenarios have been modeled with the commercial software package, NATASHA (Network Algorithm for Transient And Steady Hydraulic Analysis). The complete pipeline system, including reaction times and the potential leak scenarios, were determined as separate analytical scenarios using the software program.

## 5.1 Oil Spill Volume Prior to Leak Detection

The length of time to detection is dependent on the sensitivity and detection threshold of the detection system and the spill flow rate. As a result, dependence on the leak detection system alone could allow pinhole leaks to go undetected for days. Aerial inspections play a major role in detection of very small leaks.

The regularly scheduled Twin Otter flights to and from the Alpine production facility, as well as flights to the village of Nuiqsut and beyond, would be routed over the pipeline. The aircraft is equipped with a forward-looking infrared (FLIR) system, which can detect very small temperature differences. This equipment is also capable of identifying areas where the pipeline insulation is damaged or saturated with water, both indicators of possible external corrosion and/or pipe damage. Preventative maintenance can then be scheduled.

The volume of oil spilled before the leak is detected is a function of the leak rate and the leak detection system sensitivity. A small, low rate leak can spill substantially more oil before it is detected than a larger, high rate leak. Assuming a 0.35% of flow leak detection limit, the system's leak detection threshold for a pinhole leak is approximately 7 gallons per minute or 244 bbls per day. If the pipeline leak detection system cannot "see" this leak and the visual inspection interval conforms to CFR 195.412, Paragraph A ("Each Operator shall, at intervals not exceeding 3 weeks, but at least 26 time each calendar year, inspect the surface conditions on the right-of-way."), then as much as 5124 barrels could be spilled before it is visually detected. However, a spill volume this large is unlikely even if the leak rate is below the leak detection threshold. In practice, the "overs" and "unders" trending would indicate that a problem existed and a visual inspection would be performed. In comparison, any leak above the detection threshold should be quickly identified resulting in a much lower volume of oil spilled before detection.

In the event of a catastrophic failure, it is assumed that the entire line pack depressurizes through the leak during the time to detection phase.

Table 5-1 shows that the amount of oil spilled for each of the comparable cases is the same.

Table 5-1. Volume of Oil Spilled Before Detection (bbls)

| | Colville R. | Kachemach R. | Miluveach R. |
|---|---|---|---|
| **Isolation Valves** | | | |
| Pinhole under Threshold | 5124 | 5124 | 5124 |
| Pinhole over Threshold | 0.09 | 0.09 | 0.09 |
| Catastrophic Failure | 279.2 | 279.2 | 279.2 |
| **Vertical Loops** | | | |
| Pinhole under Threshold | 5124 | 5124 | 5124 |
| Pinhole over Threshold | 0.09 | 0.09 | 0.09 |
| Catastrophic Failure | 279.2 | 279.2 | 279.2 |

## 5.2 Oil Spill Volume During Operator Reaction

The pump runtime after detection of a pinhole leak depends on whether the shutdown system is automated, or it must depend on operator response. An automated system could be shutdown in minutes while an operator directed shutdown could take hours depending on the operators interpretation of the data supplied by the system. In either case the closure signal for remote actuated block valves is usually sent at the same time the pump shutdown signal is sent. The valve time to close, which is based on fluid hammer calculations, is then measured in seconds to minutes. In contrast, the time to closure for manually operated valves can be measured in hours to days, depending on the time of year, weather conditions and available vehicles for access to the valves.

As noted above, the pump runtime after leak detection is dependent on whether the shutdown system is automated or it must depend on operator response. An automated system could send a pump stop signal within 30 seconds. However, an automated system takes away operator discretion, potentially initiating unjustified or nuisance valve closures. An automated system, tuned and adjusted to avoid nuisance valve closures, would not be significantly faster than an operator controlled system. In the case of a catastrophic failure, the operator response time to shut down the pumps would be nearly as fast as an automated system. Intermediate sized leaks, those in the range between the detection threshold and the catastrophic failure, would require more time to verify. Obviously, the time to verify is dependent on the size of the leak with large leaks taking the least time. However, the time to verify is not proportional to the size of the leak. Visual verification of leaks just above the detection threshold could take as long as 12 hours. This uncertainty in time to verify results in assuming, for the purposes of this report only, that the operating philosophy of the Alpine pipeline will be to treat all leak alarms as leaks where the line would be shutdown immediately on detection. It is assumed for this report that the operator reaction time for all leaks is 60 seconds. In reality, low-level leaks will be visually verified before the pipeline is shutdown.

Table 5-2 shows there is no difference in spill volumes between the isolation block valve case and the vertical loop case for all scenarios.

**Table 5-2. Volume of Oil Spilled During Operator Reaction (bbls)**

| | Colville R. | Kachemach R. | Miluveach R. |
|---|---|---|---|
| **Isolation Valves** | | | |
| Pinhole under Threshold | 0.17 | 0.17 | 0.17 |
| Pinhole over Threshold | 0.17 | 0.17 | 0.17 |
| Catastrophic Failure | 48.6 | 48.6 | 48.6 |
| **Vertical Loops** | | | |
| Pinhole under Threshold | 0.17 | 0.17 | 0.17 |
| Pinhole over Threshold | 0.17 | 0.17 | 0.17 |
| Catastrophic Failure | 48.6 | 48.6 | 48.6 |

## 5.3 Oil Spill Volume During Valve Closure and Pipeline Depressuring

The major contributor to the volume of oil spilled due to a pinhole leak is the amount spilled before detection. At that point, the pipeline can be quickly shutdown and depressured thus eliminating the motive force for the spill. As noted above, the pump runtime is a function of the system or operator response time.

The signal to close the block valves would be sent at the same time as the pump shutdown signal. The pipeline block valves are designed to close as fast as possible without generating severe hydraulic transients that may overpressure the pipeline. The approximate volume of oil spilled during valve closure is manually calculated by multiplying the flow rate by the valve close time divided by two. The accuracy is significantly impacted by opening the emergency pressure relief valves located at the pipeline inlet and outlet. The NATASHA program was used to model the effects of simultaneous relief valve opening and block valve closing and accurately calculates the volume spilled.

The vertical loop equipped pipeline is not dependent on isolation block valve closure to stop depressurization through a leak. The instant the pumps are stopped, the line depressurizes through the pressure relief valves. Inertia maintains flow for only a few moments and has no significant effect on total volume.

There are two components to the volume of oil spilled due to a pipeline depressuring to atmospheric pressure. They are the elasticity of the pipeline and the compressibility of the oil in the pipeline. The pipeline elasticity portion is comprised of hoop stress expansion and longitudinal expansion, both due to internal pressure. The NATASHA computer program accounts for the pipeline elasticity and the oil compressibility in its calculation of the potential spills volumes for the various scenarios.

In pipelines equipped with ROVs, the isolated pipeline segment containing the leak will depressurize through the leak after the valves have closed. Slowing the operation of ROVs would reduce the amount of oil released in the depressurizing phase of a leak but this configuration runs counter to the requirement to close as fast as possible to limit a release in the event of a catastrophic failure. An ROV that fails to close could allow release of the entire line pack. This also applies to manual block valves since they will have long close times. Emergency pressure relief valves have been incorporated in the pipeline design for both the valved case and the vertical loop case to quickly drop the pipeline pressure and reduce the potential oil spill volume. Emergency pressure relief valves do not provide any spill volume reduction benefit to ROV equipped pipelines with pinhole leaks since

the ROVs isolate the pressurized segments as noted above. Emergency relief valves are very effective with manual block valves for pipeline depressuring due to the long block valve close time but have very little effect if ROVs are installed.

**Table 5-3. Volume of Oil Spilled During Valve Closure and Pipeline Depressuring (bbls)**

| | Colville R. | Kachemach R. | Miluveach R. |
|---|---|---|---|
| **Isolation Valves** | | | |
| Pinhole under Threshold | 16.77 | 0.27 | 0.25 |
| Pinhole over Threshold | 16.79 | 0.32 | 0.32 |
| Catastrophic Failure | 24.31 | 24.31 | 24.31 |
| **Vertical Loops** | | | |
| Pinhole under Threshold | 0.29 | 0.26 | 0.26 |
| Pinhole over Threshold | 0.29 | 0.30 | 0.26 |
| Catastrophic Failure | 24.31 | 24.31 | 24.31 |

As noted above, it is assumed that the entire line pack depressurizes through the leak during the time to detection phase in the event of a catastrophic failure.

## 5.4 Oil Spill Volume Due to Pipeline Draindown

Pipeline drainage can be the largest contributor to total pipeline spill volumes. The purpose of isolation block valves is to limit the volume of oil spilled due to drainage. However, their effectiveness depends on the valve close time. Remote actuated block valves can be very effective in reducing the volume due to drainage. Manual block valves are less effective. However, pipeline drainage contributes little to the total spill volume associated with pinhole leaks so automating or remotely actuating the block valves has little to no effect on reducing the volume of oil released. It is assumed that the manual block valve close time is on the order of twelve hours. This length of time accounts for equipment and crew mobilization and travel time to the block valves during severe weather. This extended close time would allow a substantial portion of the oil uphill from the leak to spill out through the leak in the event of a catastrophic failure.

Table 5-4 above shows that manual isolation block valves are not as effective as ROVs for reducing the amount of oil spilled in the pipeline drainage case. However, any benefit gained by installing actuated valves at the Kachemach and Miluveach Rivers is offset by the increased volume of oil spilled in the pipeline depressuring case with the result being no net improvement. Vertical loops are slightly more effective than manual block valves at limiting drainage spill volumes due to pinhole leaks. Vertical loops offer a substantial advantage over manual block valves for the drainage component due catastrophic failure.

Table 5-4. Volume of Oil Spilled Due to Pipeline Drainage (bbls)

| | Colville R. | Kachemach R. | Miluveach R. |
|---|---|---|---|
| **Isolation Valves** | | | |
| Pinhole under Threshold | 1.00 | 13.94 | 10.26 |
| Pinhole over Threshold | 1.00 | 14.02 | 10.33 |
| Catastrophic Failure | 2375.5 | 6158.1 | 4615.8 |
| **Vertical Loops** | | | |
| Pinhole under Threshold | 11.78 | 11.90 | 8.82 |
| Pinhole over Threshold | 11.83 | 11.95 | 8.88 |
| Catastrophic Failure | 871.6 | 126.4 | 375.6 |

## 5.5 Oil Spill Volume Summary

The total volume of oil spilled in all the scenarios is the sum of the components identified and is shown in Table 5-5. The table shows that vertical loops installed in lieu of isolation block valves results in less oil released in all scenarios evaluated.

Table 5-5. Total Volume of Oil Spilled (bbls)

| | Colville R. | Kachemach R. | Miluveach R. |
|---|---|---|---|
| **Isolation Valves** | | | |
| Pinhole under Threshold | 5141.9 | 5138.4 | 5134.7 |
| Pinhole over Threshold | 18.0 | 14.6 | 10.9 |
| Catastrophic Failure | 2727.6 | 6510.2 | 4967.9 |
| **Vertical Loops** | | | |
| Pinhole under Threshold | 5136.2 | 5136.4 | 5133.2 |
| Pinhole over Threshold | 12.4 | 12.5 | 9.4 |
| Catastrophic Failure | 1223.8 | 478.6 | 727.7 |

# 6.0 Summary and Conclusions

The four major components that contribute to spill volume (time to detection, operator response, pipeline depressurization, and pipeline drainage) have been evaluated for both the isolation block valve and vertical loop alternatives. They were evaluated by consideration of pinhole leaks and a complete guillotine failure for each alternative.

It can be concluded that manual isolation valves, in combination with emergency relief valves, are superior to ROVs for the pipeline depressuring case and that remote operated valves are marginally superior to manual isolation valves and vertical pipeline loops only for the pipeline drainage case in the event of a pinhole leak. However, vertical pipeline loops, in combination with emergency relief valves, are superior to both remote operated valves and manual operated valves for the following reasons:

- The total volume of spilled oil due to both pinhole and catastrophic pipeline failures is greater with both ROVs and manual isolation block valves than with vertical loops and emergency relief valves.
- Valves increase the risk of spills by introducing potential leak sources.
- Vertical loops do not require tundra access for inspection or maintenance. Vertical loops can be optimally sited to minimize spill volumes since their siting does not have to take into account access for maintenance activities since they do not require maintenance.
- Manual isolation block valves require access to use. Vertical loops are passive and do not require operator action to be used.
- Valves can fail. Vertical loops have no fittings or moving parts to fail.

It is concluded that vertical pipeline loops are considerably more effective in minimizing spill volumes during spill events. In addition, the increased possibility of oil leakage at the mechanical connections of the valves, traditionally an area of concern and maintenance, is eliminated.

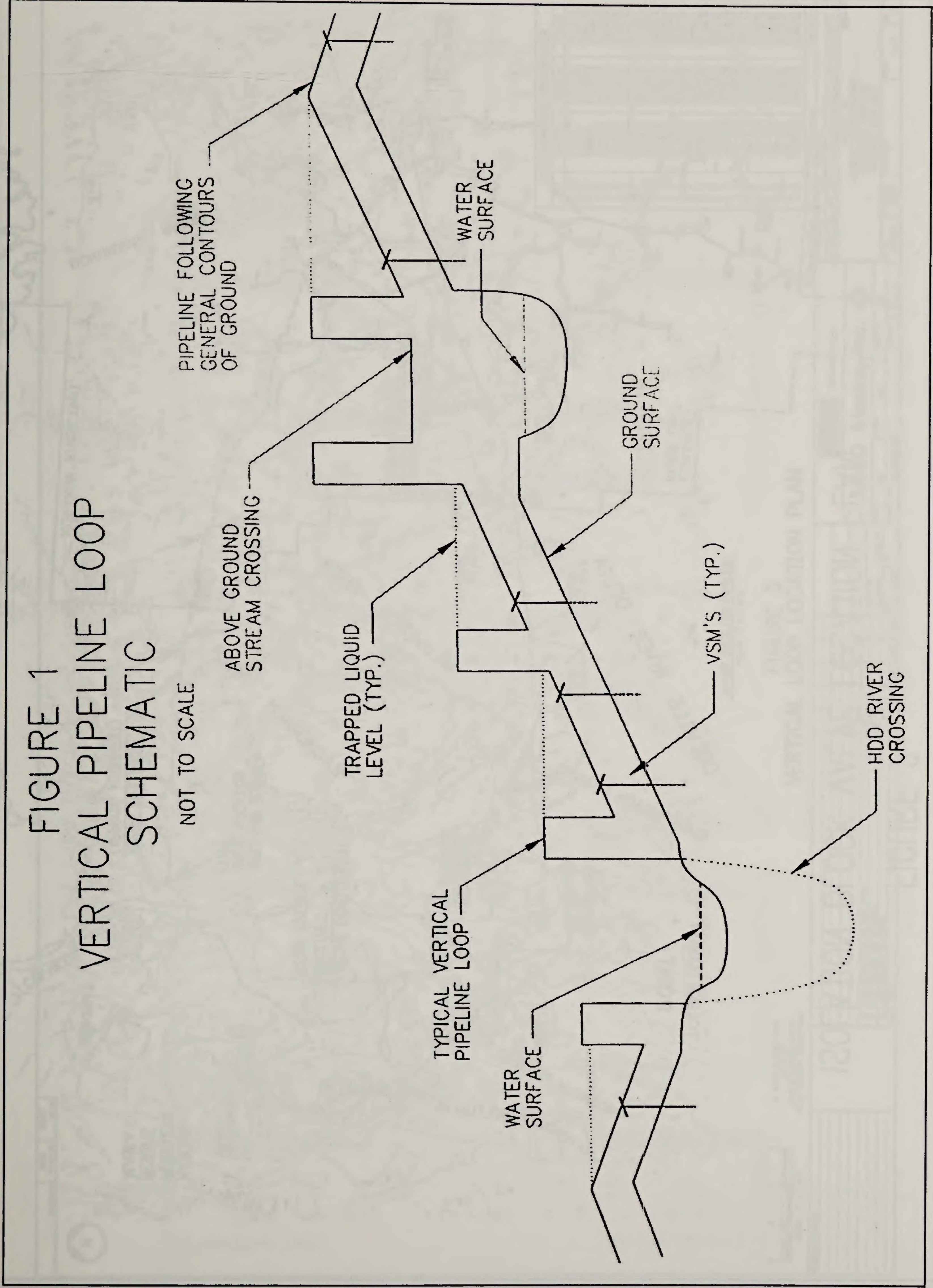



**Figure 1. Vertical Pipeline Loop Schematic**

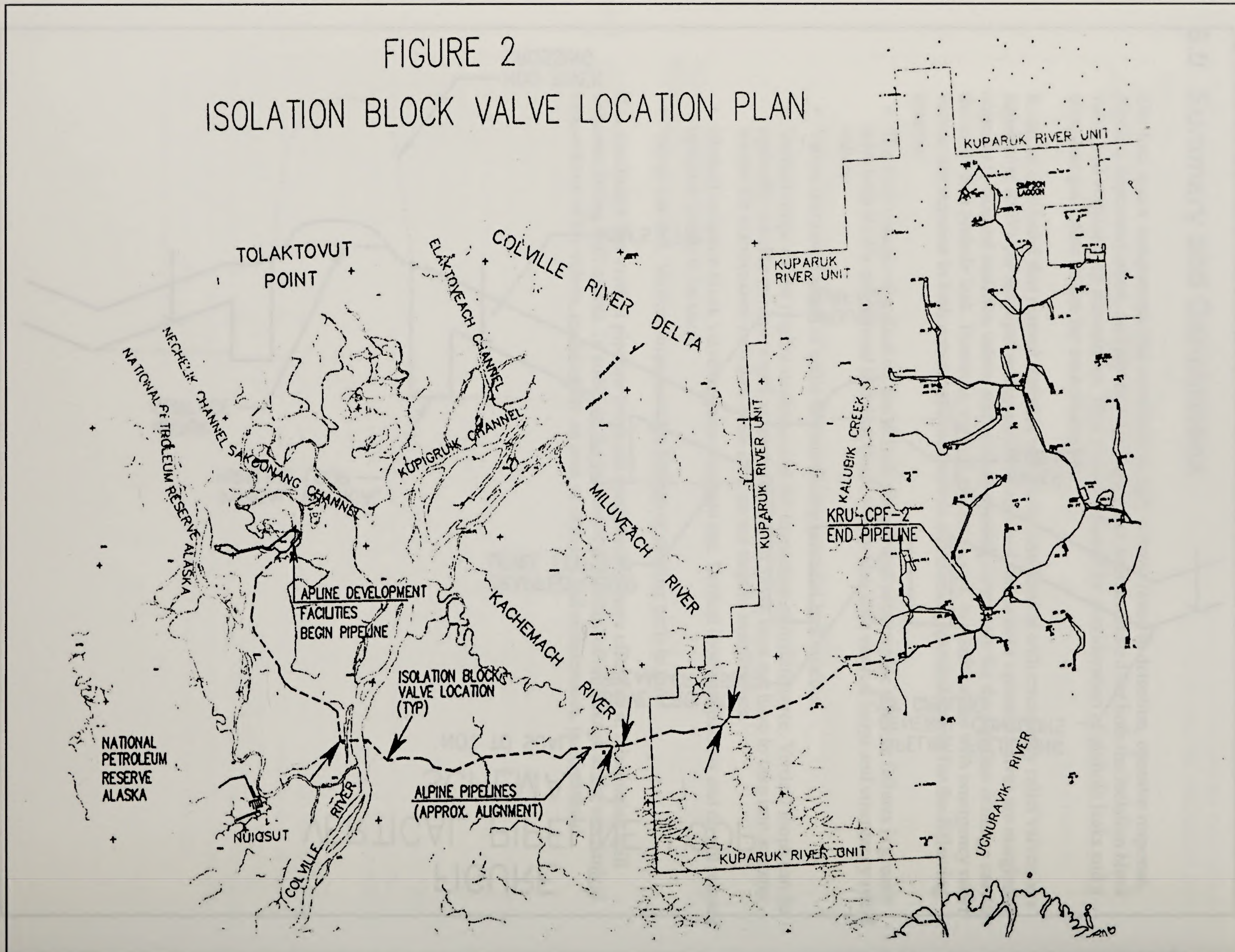
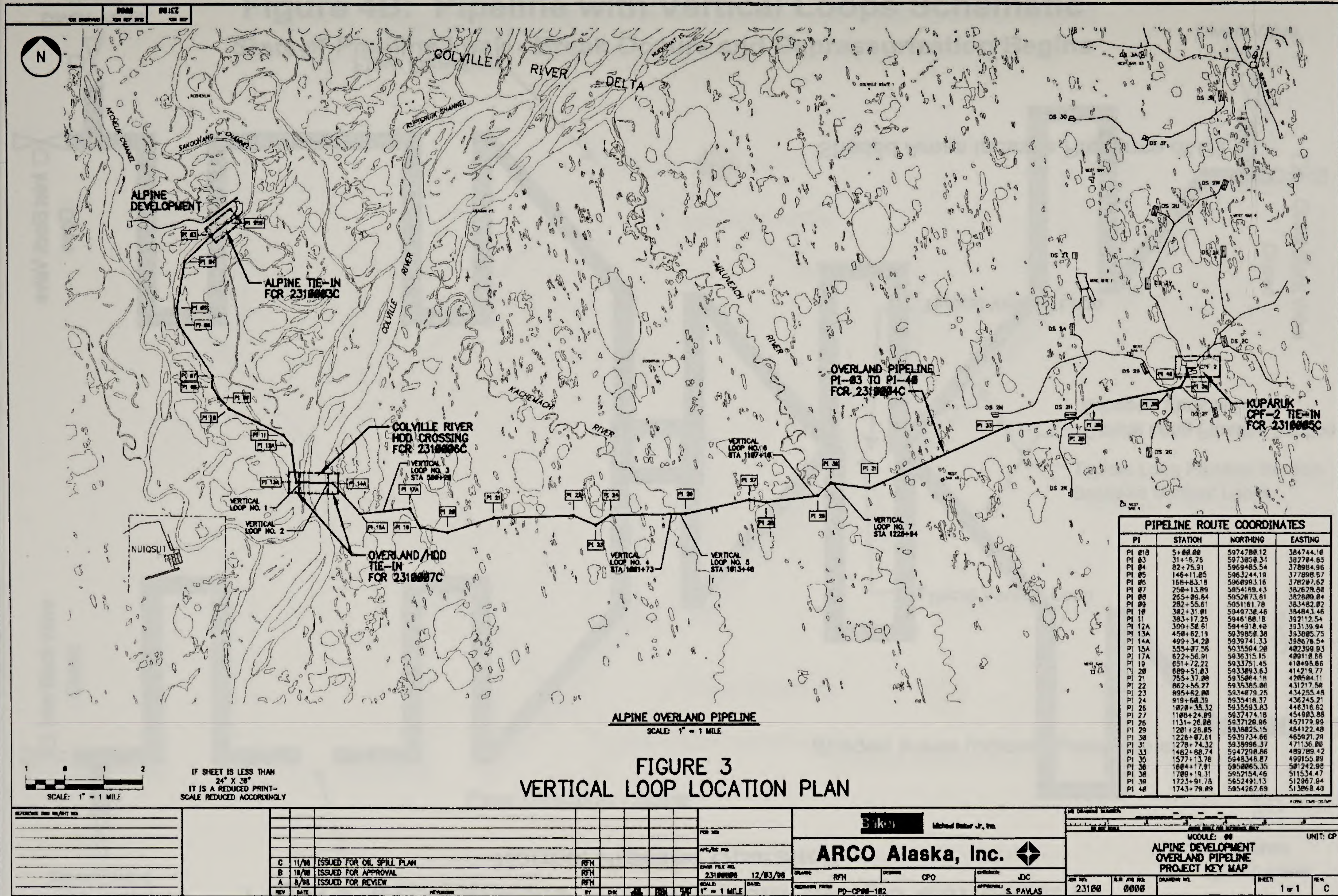



**Figure 2. Isolation Block Valve Location Plan**

Figure 3. Vertical Loop Location Plan




| PIPELINE ROUTE COORDINATES | | | |
|---|---|---|---|
| PI | STATION | NORTHING | EASTING |
| PI 010 | 5+00.00 | 5974700.12 | 384744.10 |
| PI 03 | 31+16.76 | 5973030.34 | 382704.85 |
| PI 04 | 82+75.91 | 5969485.54 | 378984.96 |
| PI 05 | 146+11.05 | 5963244.19 | 377898.57 |
| PI 06 | 168+83.18 | 5960993.16 | 378207.62 |
| PI 07 | 250+13.89 | 5954160.43 | 382628.60 |
| PI 08 | 265+09.84 | 5952673.61 | 382600.04 |
| PI 09 | 282+55.61 | 5051161.78 | 383482.02 |
| PI 10 | 302+31.01 | 5949730.46 | 384843.46 |
| PI 11 | 383+17.25 | 5946188.18 | 392112.54 |
| PI 12A | 399+50.61 | 5944918.40 | 393139.94 |
| PI 13A | 450+62.19 | 5939850.38 | 393805.75 |
| PI 14A | 499+34.20 | 5939741.33 | 398676.54 |
| PI 15A | 555+07.56 | 5935504.20 | 402399.93 |
| PI 17A | 622+56.91 | 5936315.15 | 409110.66 |
| PI 19 | 651+72.22 | 5933751.45 | 410495.66 |
| PI 20 | 689+51.03 | 5933093.63 | 414219.77 |
| PI 21 | 755+37.00 | 5935004.18 | 420504.11 |
| PI 22 | 862+56.27 | 5935365.06 | 431217.50 |
| PI 23 | 895+62.00 | 5934079.25 | 434255.48 |
| PI 24 | 919+60.39 | 5935418.37 | 436245.21 |
| PI 26 | 1020+35.32 | 5935593.83 | 446316.62 |
| PI 27 | 1100+24.09 | 5937474.18 | 454903.88 |
| PI 28 | 1131+26.08 | 5937120.96 | 457179.99 |
| PI 29 | 1201+26.05 | 5938025.15 | 464122.48 |
| PI 30 | 1226+07.61 | 5939734.66 | 465921.29 |
| PI 31 | 1278+74.32 | 5938996.37 | 471136.00 |
| PI 33 | 1482+88.74 | 5947290.86 | 489789.42 |
| PI 35 | 1577+13.78 | 5948346.87 | 499155.09 |
| PI 36 | 1604+17.91 | 5950065.35 | 501242.98 |
| PI 38 | 1709+19.31 | 5952154.46 | 511534.47 |
| PI 39 | 1723+91.78 | 5952491.13 | 512967.94 |
| PI 40 | 1743+79.09 | 5954262.69 | 513868.40 |

## Figure 4A: Pipeline with Vertical Loops Schematic

### Normal Pipeline Operation

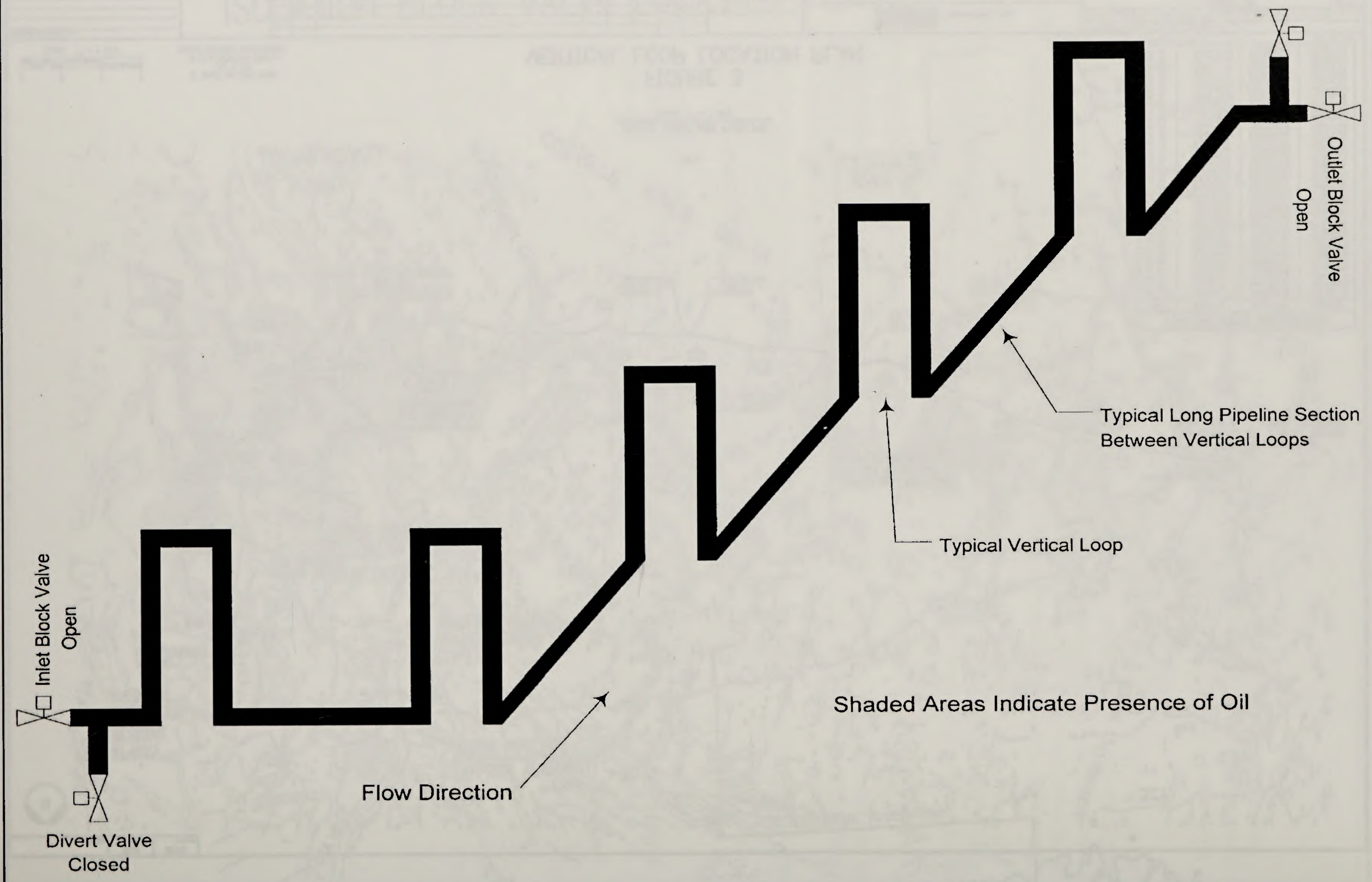
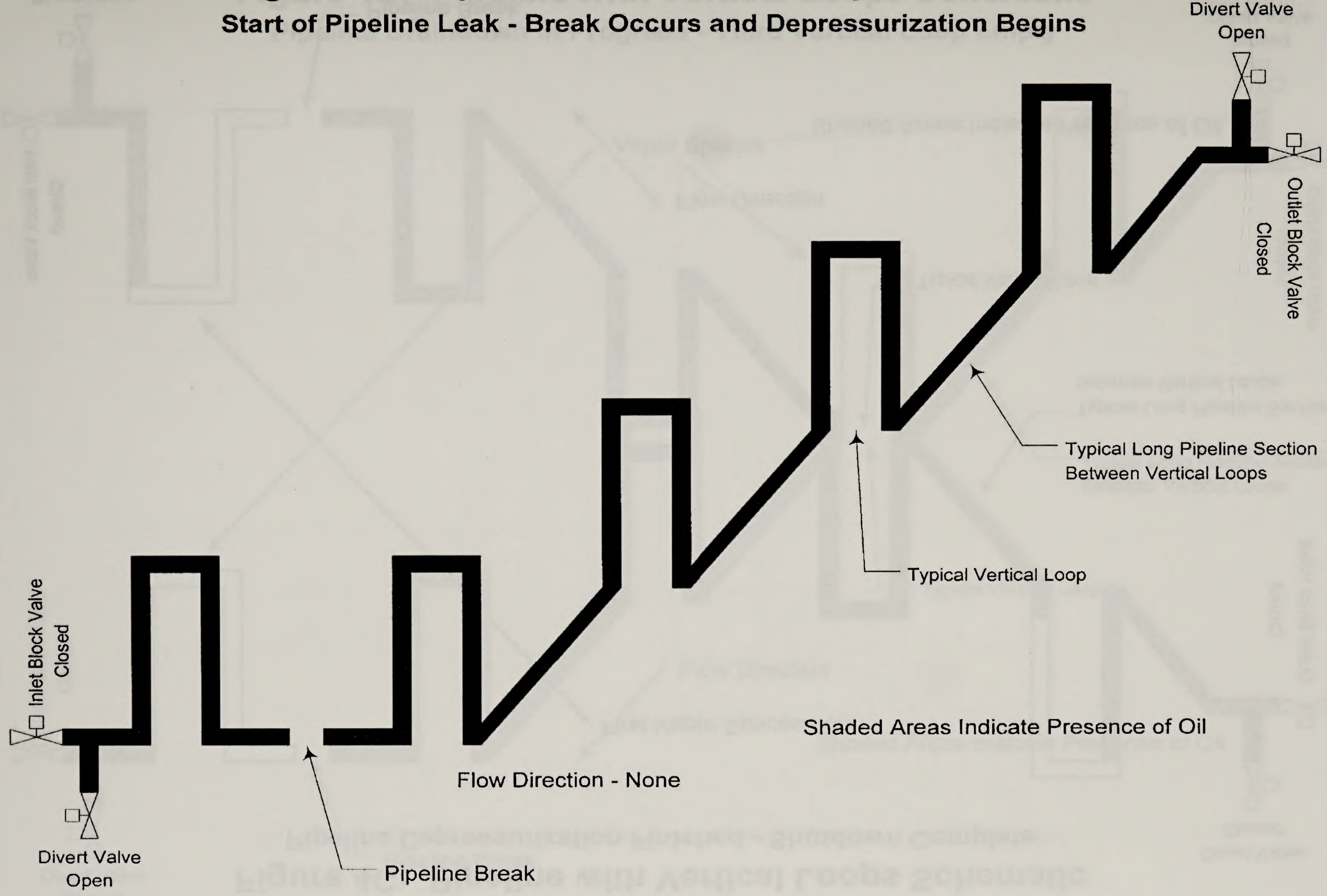



**Figure 4. Pipeline with Vertical Loops Schematic**

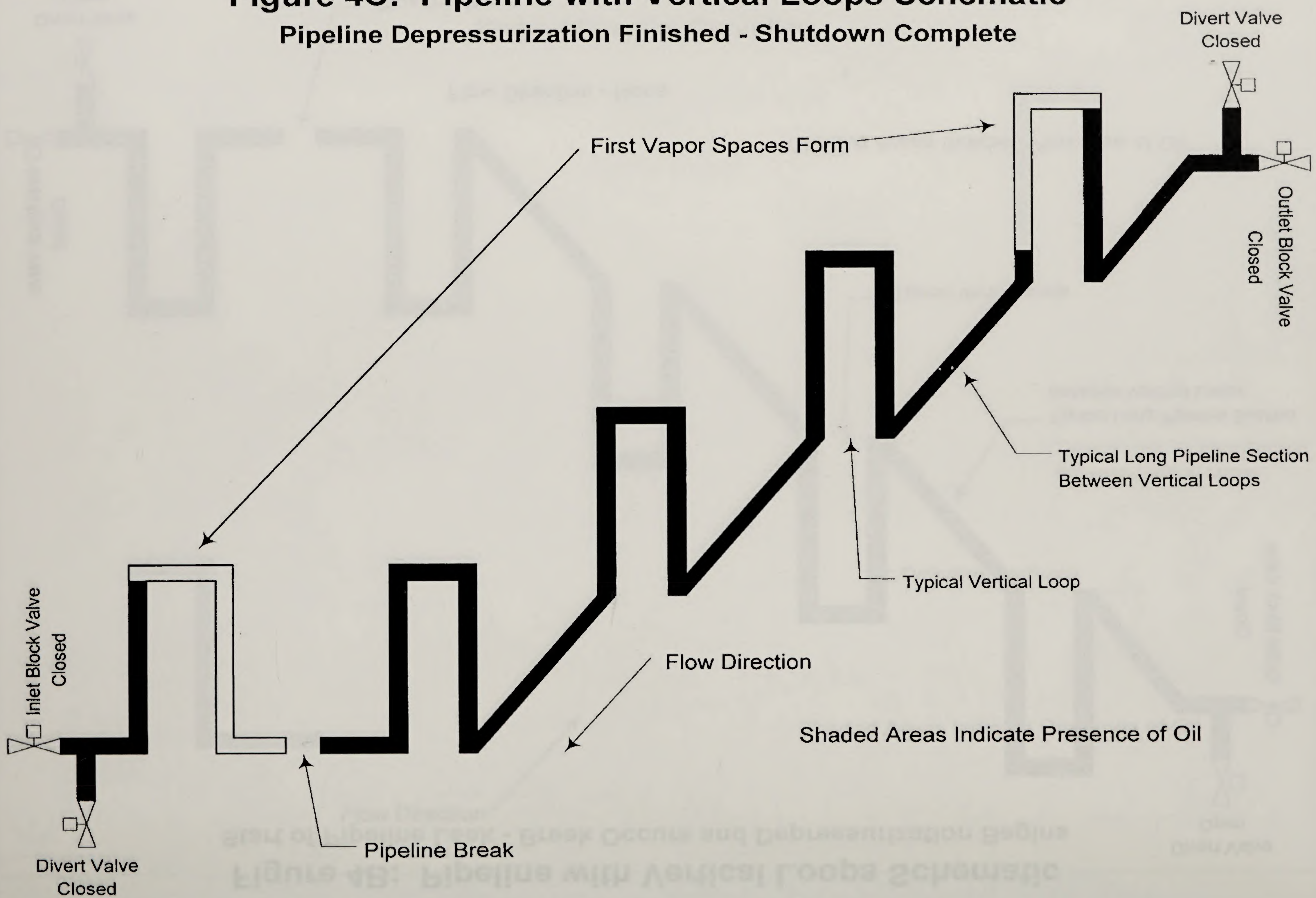
## Figure 4B: Pipeline with Vertical Loops Schematic

### Start of Pipeline Leak - Break Occurs and Depressurization Begins



## Figure 4C: Pipeline with Vertical Loops Schematic

### Pipeline Depressurization Finished - Shutdown Complete



## Figure 4D: Pipeline with Vertical Loops Schematic

**Pipeline Draindown in Progress - Third Vertical Loop Empty**

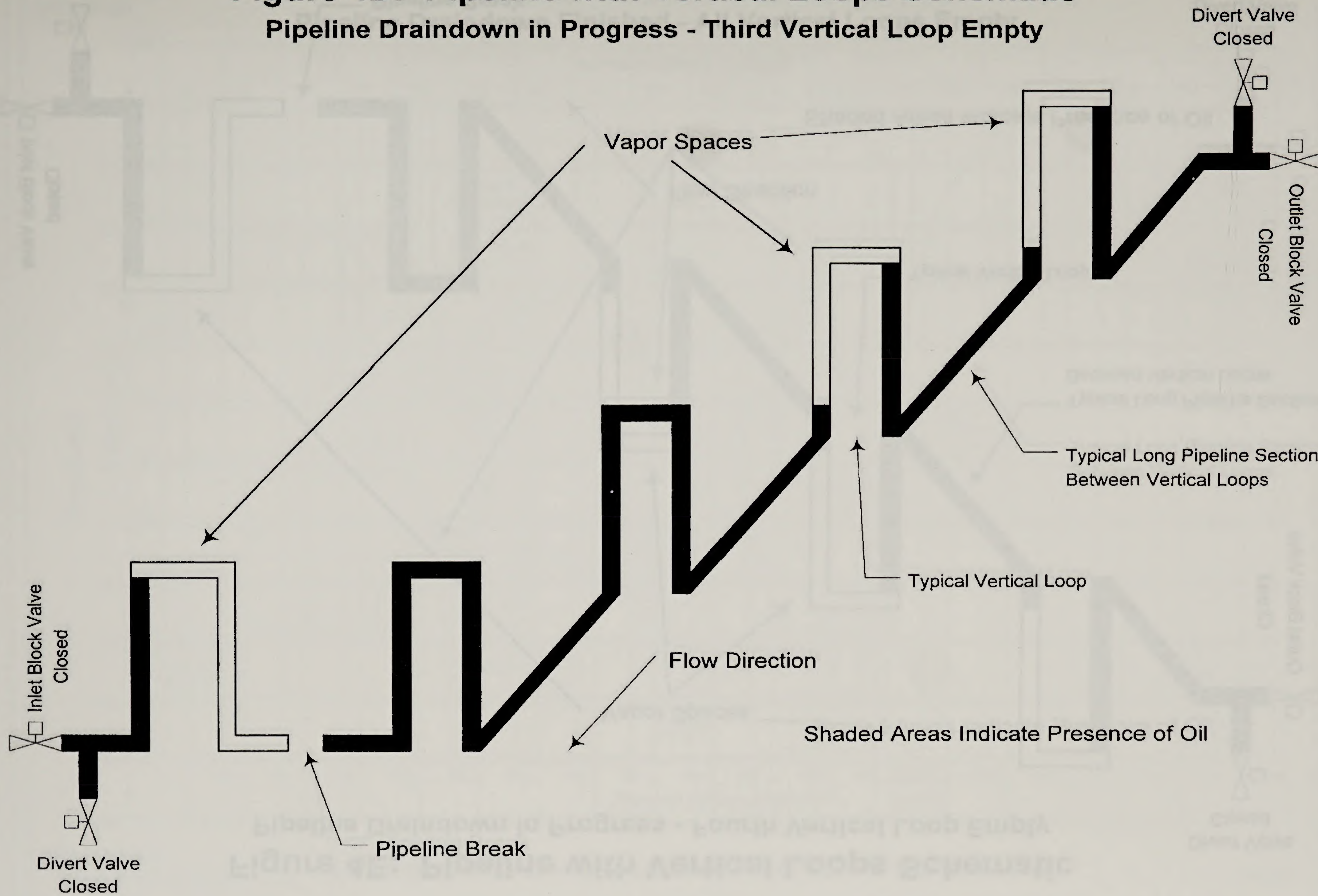
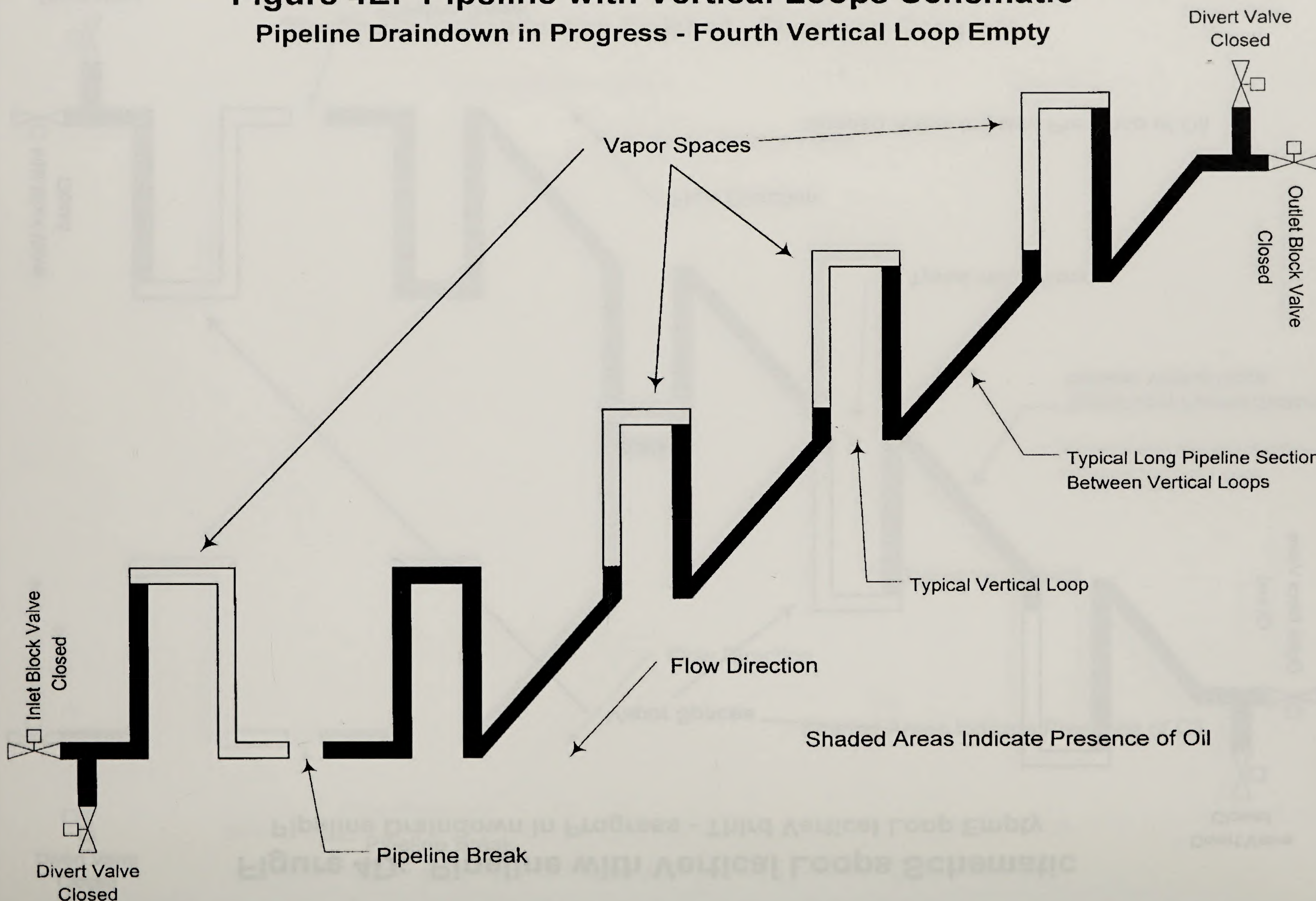


Figure 4. (cont'd)

# Figure 4E: Pipeline with Vertical Loops Schematic

## Pipeline Draindown in Progress - Fourth Vertical Loop Empty



# Figure 4F: Pipeline with Vertical Loops Schematic

## Pipeline Draindown Finished - All Vertical Loops Empty

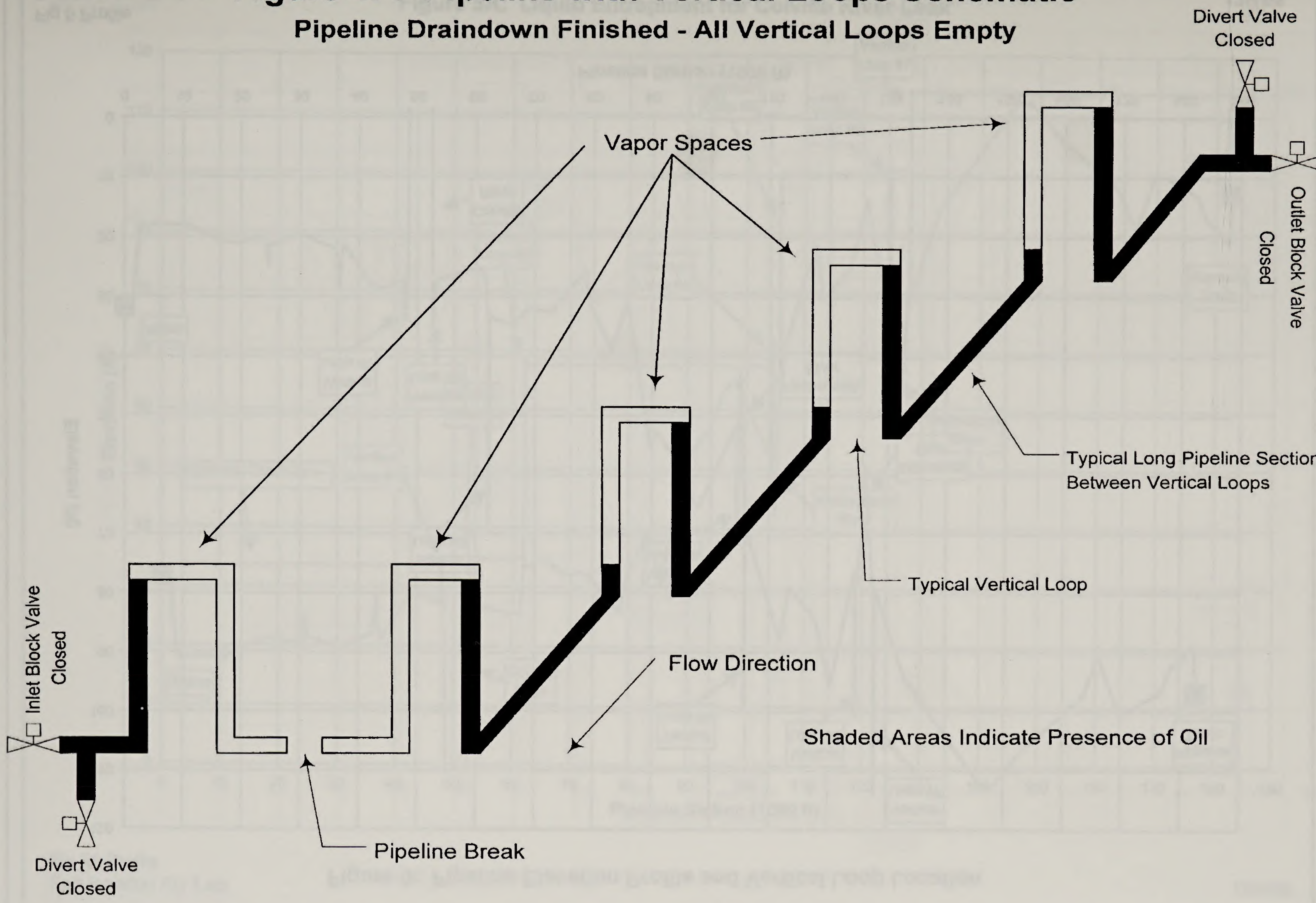


Figure 5. Pipeline Elevation Profile and Vertical Loop Location

## Figure 5: Pipeline Elevation Profile and Vertical Loop Location

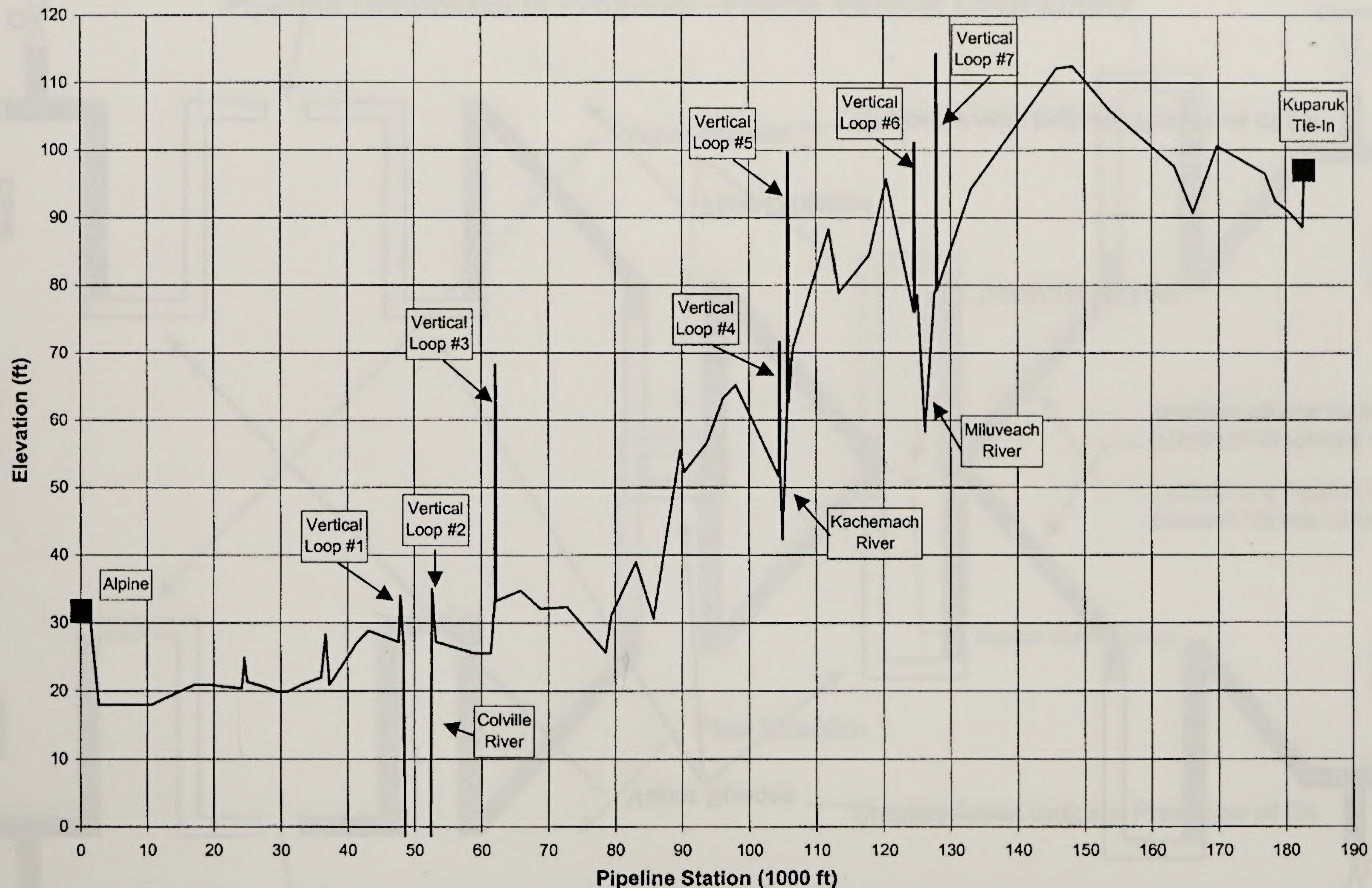



Fig 5 Profile
Spill Isolation Fig 2.xls

12/4/98

Figure 5A: Liquid Entrapment for Colville River Leak

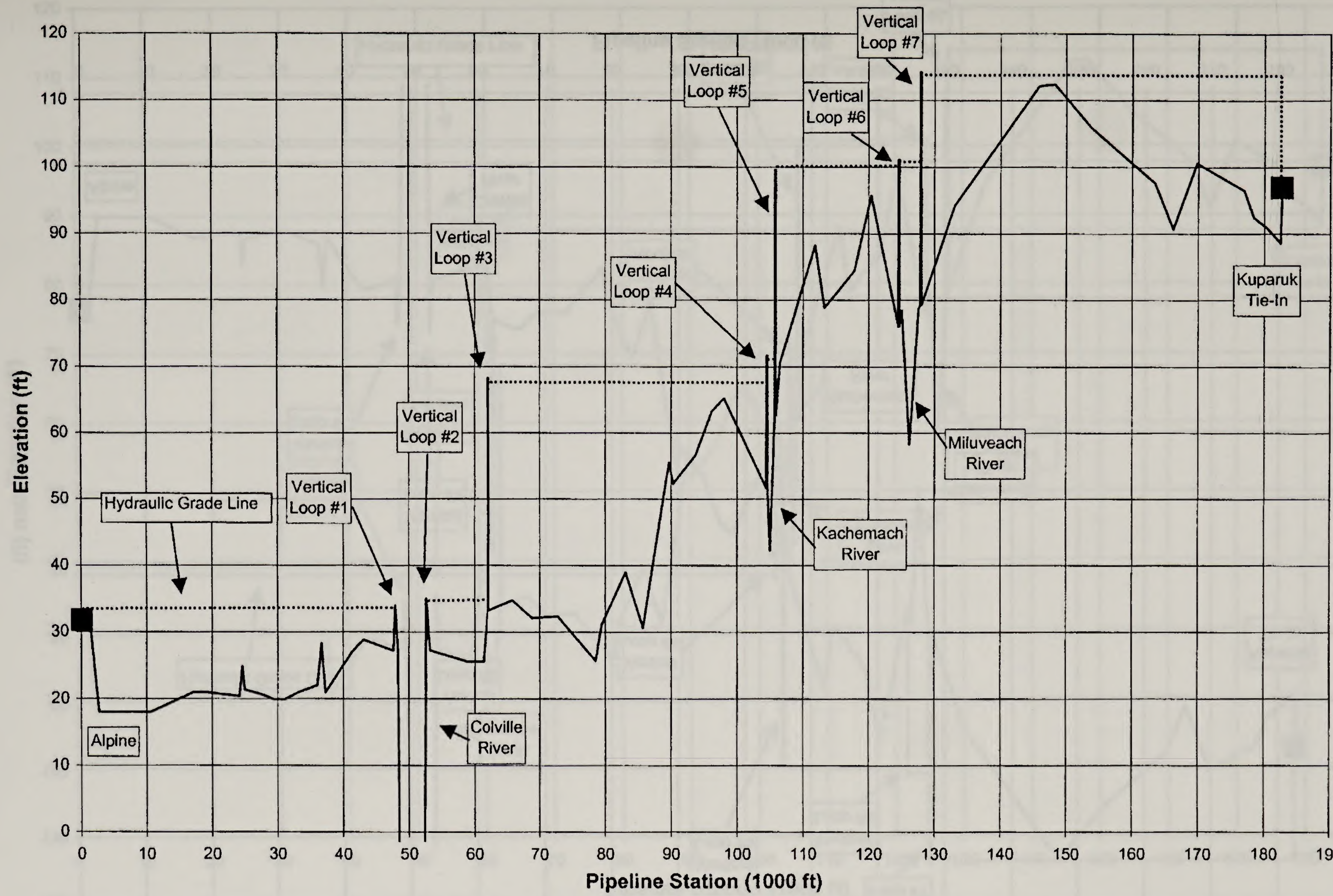



Fig 5A Profile
Spill Isolation Fig 2.xls

12/4/98

**Figure 5. (cont'd) Liquid Entrapment for Colville River Leak**

Figure 5. (cont'd) Liquid Entrapment for Kachemach River Leak

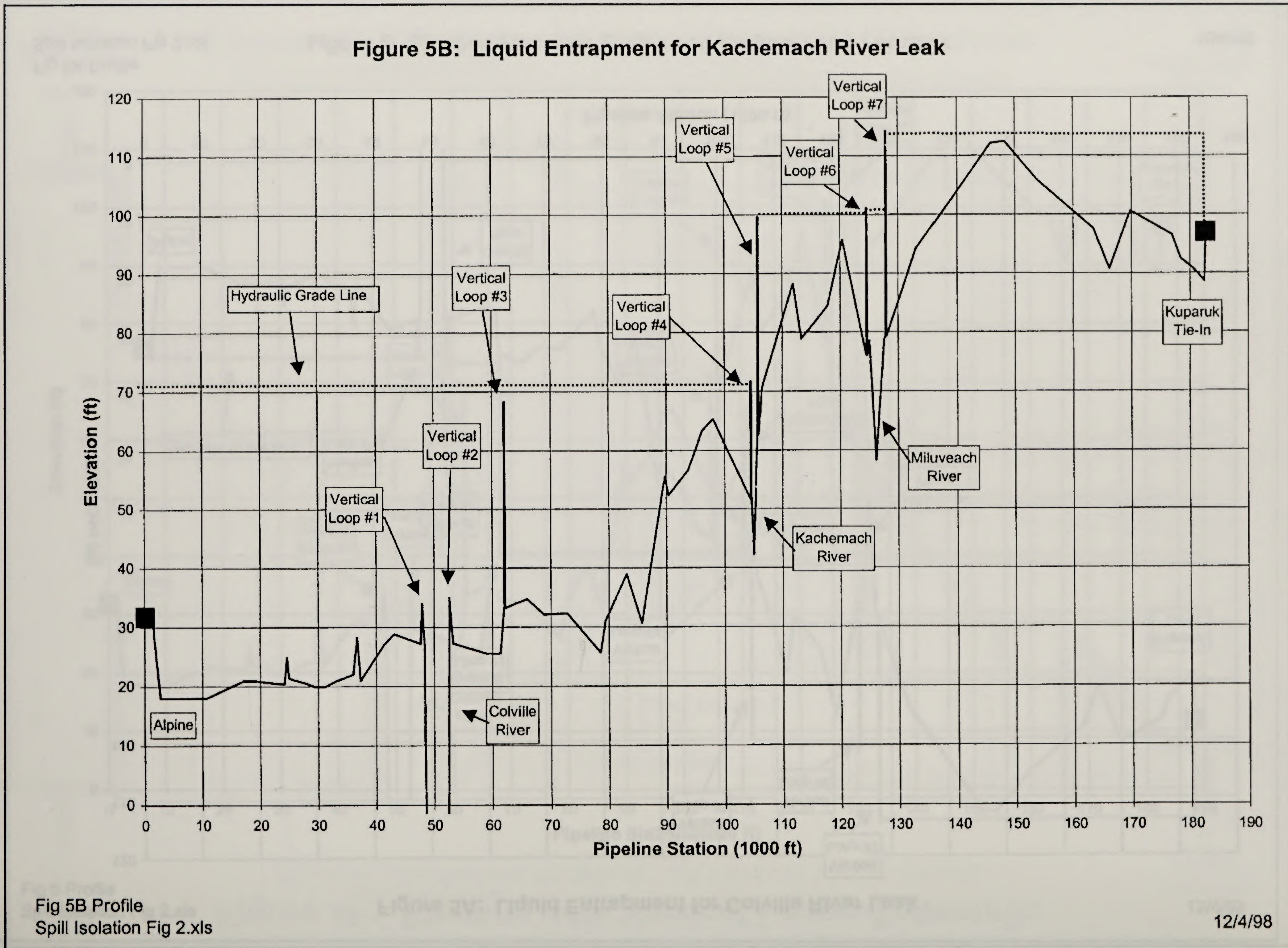


Figure 5. (cont'd) Liquid Entrapment for Miluveach River Leak

## Figure 5C: Liquid Entrapment for Miluveach River Leak

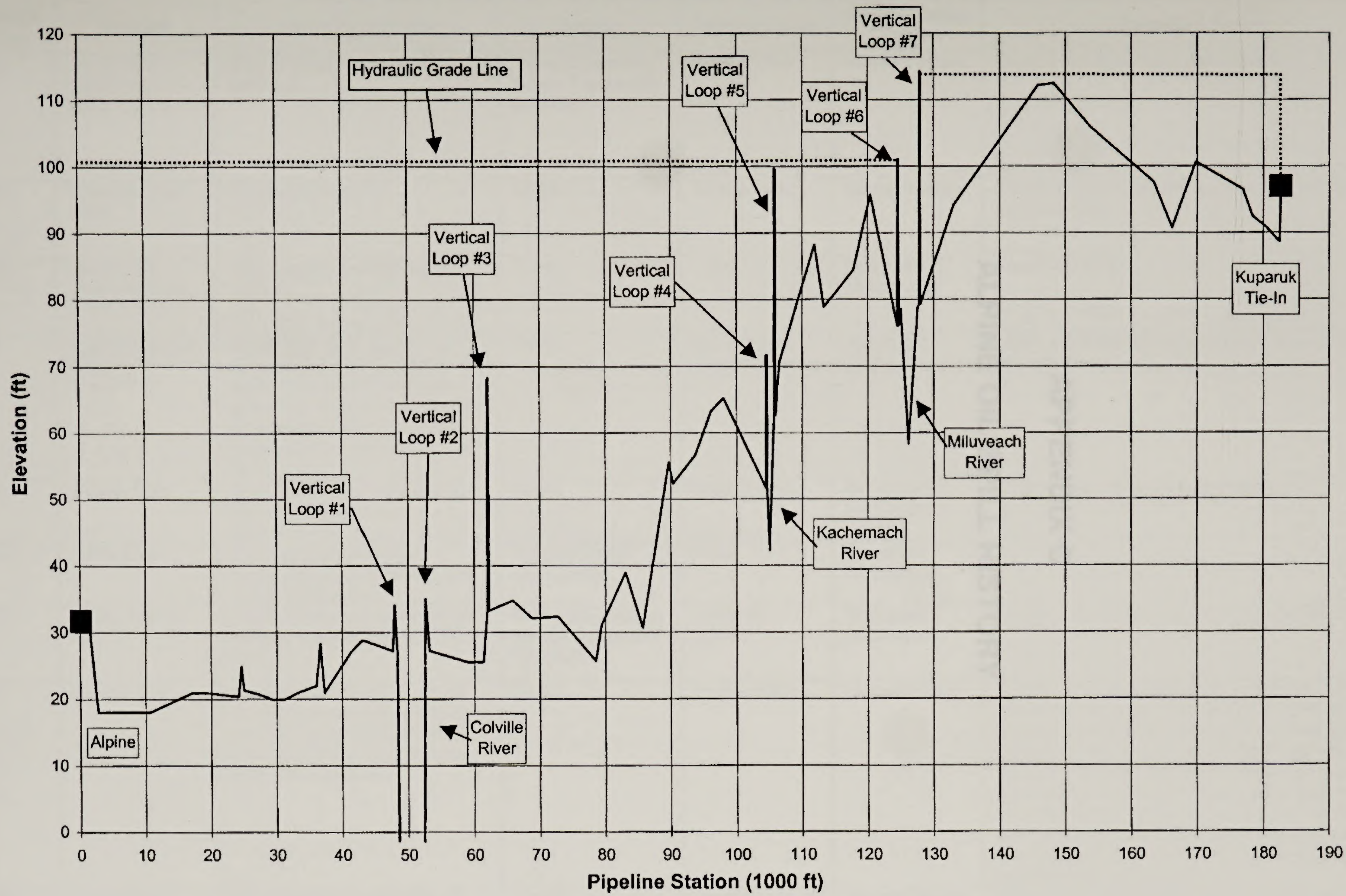



Fig 5C Profile
Spill Isolation Fig 2.xls

12/4/98

# APPENDIX C

# ALPINE OIL SPILL HISTORY

BLANK PAGE

# TABLE C-1: ALPINE HISTORY OF OIL SPILLS GREATER THAN 55 GALLONS

| Date | Location | Volume (Gal) | Product | Cause Explanation | Source | General Cause | General Cause Category | Corrective Action |
|---|---|---|---|---|---|---|---|---|
| 5/4/1999 | Alpine | 252 | Diesel-98%, Glycol-1%, Motor Oil-1% | Traveling too fast for road condition. | Heavy Equipment/ Mobile Equipment/ Vehicles | Human Error | Human Factors | Reduce speed during warm weather. |
| 4/24/2000 | Mud Plant | 500 | Hydraulic Fluid-100% | Cargo not secured. | Tanks | Human Error | Human Factors | Ensure cargo is properly secured for working environment. |
| 1/5/2001 | M1 WWTP | 210 | Diesel-95%, Grey water-5% | High/Low level control on tank failed. | Tanks | Leak | Structural/ Mechanical | Repair Controls |
| 2/14/2001 | CD-1 | 75 | Hydraulic Fluid-100% | Sight glass hose failure on a hydraulic tank inside a lube truck. Tubing failure on sight glass was caused by excessive heat from a 28kW generator inside the box unit of the Lube truck. | Tanks | Gauge/ Site Glass Failure | Structural/ Mechanical | Install a thermostatically controlled vent in the box unit of the lube truck. |
| 3/29/2001 | CD-1 | 126 | Diesel-100% | Tank fill valve not closed. (Spill was all to secondary containment) | Tanks | Valve Failure | Structural/ Mechanical | Review/revise tank filling procedures |
| 7/15/2001 | CD2-33 | 252 | 100% Other | Flow line plugged while cementing surface casing and spilled drilling mud. | Fittings/ seals/ connections | Leak | Structural/ Mechanical | |
| 9/25/2001 | Airstrip | 600 | 100% Aviation Fuel | Aviation accident; unavoidable collision caused damage to fuel tank. | Heavy Equipment/ Mobile Equipment/ Vehicles | Collision/ Allison | Structural/ Mechanical | Review aviation procedures for take off/landing. |
| 5/11/2002 | CD1-25 | 64 | Diesel-100% | The tank return valve was not closed between completing one process and starting another operation. As a result the diesel tank was overfilled. | Tanks | Human Error | Human Factors | 1. This hot oil unit has high level alarms (audible with small red lights) they are going to install a flashing beacon to this system also, this should increase alarm awareness. 2. Little Red will also put together a new spill prevention awareness presentation that covers recent spills as well as ways to prevent further spills, they did this last year, and it was very effective. It includes a open forum with all employees, looking for ways to improve spill performance. |
| 12/17/2002 | Mud Plant | 275 | Mineral Oil-100% | While transferring mineral oil into tank, tank was overfilled. Spill was contained in a lined secondary area. | Tanks | Overfill | Human Factors | A Tap Root investigation was conducted on this spill to determine the root cause of the spill and the recommended remedial actions. The remedial actions include updating procedures and auditing of those procedures. |

## TABLE C-1 (CONTINUED): ALPINE HISTORY OF OIL SPILLS GREATER THAN 55 GALLONS

| Date | Location | Volume (Gal) | Product | Cause Explanation | Source | General Cause | General Cause Category | Corrective Action |
|---|---|---|---|---|---|---|---|---|
| 3/18/2004 | CD2 | 420 | Diesel-100% | Hose failure on frac tank. | Transfer hoses | Equipment Failure | Structural/ Mechanical | 1. Place Frac Tank Equipment in Schlumberger's STEM tracking database for PM. Perform PM of Frac Tank Equipment annually. 2. Assure a Frac Crew representative is present when setting up Frac tanks and manifold. Add this step to Frac Tank Rig-Up procedure. 3. Have spare hoses available on site prior to filling tanks and throughout the frac job 4. Add steps 2&3 to SOPs for all fracs on CPA sites. |
| 3/26/2004 | Mud Plant | 67 | Diesel-100% | Overfilled fuel truck. | Heavy equipment/ mobile equipment/ vehicles | Overfill | Human Factors | 1. Develop a written fueling procedure for the fuel truck. 2. Ensure that adequate operator training and handover occurs for rental equipment. 3. Contact Airport Rentals or manufacturer and make them aware of the secondary containment drain. 4. Conduct safety/environment process review of new equipment or rented equipment coming into the field for the first time. 5. Review emergency procedures for fluid transfer stations, diesel loading, gas tank, and aviation fuel. |
| 8/11/2005 | CD4 | 136.8 | Diesel-100% | 136-gallons of diesel fuel was discovered in the Nanuq #3 well cellar from a presumed leak in the well annulus. | Pipe/flowlines/ hardlines | Unknown | Unknown | Well diagnostics were performed; however, the source of the leak could not be determined. |
| 10/2/2005 | CD2 | 500 | Produced Water-100% | The Class II storage cell liner developed a tear. | Sumps | Leak | Structural/ Mechanical | Cell liner is being inspected and repaired. |
| 4/6/2006 | CD3 | 210 | Crude-5%, Brine-95% | Approximately 2 to 5 bbls of brine (95%) and crude (5%) was blown out a flare stack during a well flow back operation on Alpine CD3 pad (well CD3-109). | Flares | Unknown | Unknown | 1. Generate a specific procedure for the test package that explains how to FCO all systems with a checklist that includes all safety systems. Require use of the checklist and procedure at all times. 2. Require use of the heater in the scrubber building. Include the heater FCO in the procedure and checklist 3. Require the use of flagging/tagging and a log for defeated safety devices. 4. Initiate a hazards analysis for the ESD system to identify situations in which safety systems do not fail safe and mitigate hazards. 5. Audit/evaluate the safety systems on the well test package to ensure effectiveness for prevention of injury and environmental damage. Include an evaluation of hazards posed by personnel working in proximity to the well test operation. |

## TABLE C-1 (CONTINUED): ALPINE HISTORY OF OIL SPILLS GREATER THAN 55 GALLONS

| Date | Location | Volume (Gal) | Product | Cause Explanation | Source | General Cause | General Cause Category | Corrective Action |
|---|---|---|---|---|---|---|---|---|
| 4/19/2006 | Mud Plant | 412 | Diesel-100% | Open valve on Triplex pump during fueling resulted in spill. | Heavy equipment/ mobile equipment/ vehicles | Human Error | Human Factors | 1. Fleet Maintenance to develop SOP for identification and tag out of any new or existing equipment that is out of service for repair or inspection. The SOP will include major systems such as Fuel, Hydraulics, Coolant and Electrical. 2. Implement minimum criteria for final inspection by CPAI representative of new equipment prior to shipping to Alpine. |
| 12/27/2006 | Mud Plant | 84 | 100% Other | While unloading vac truck into tank, operator allowed tank to overfill. Released into secondary containment. | Heavy Equipment/ Mobile Equipment/ Vehicles | Overfill | Human Factors | Review transfer procedures. |
| 1/5/2007 | CD1A | 440 | Crude-10%, Produced water-90% | A purge valve on a line from the Slop oil tank was mistakenly left open after a hydro test. When the line was placed back in service, produced water and oil spilled onto the module floor. | Fittings/seals/ connections | Human Error | Human Factors | 1. Modify gas detection system such that when the gas heads are bypassed, the alarm that sounds on the DCS when 1 gas head detects >10% LEL is not suppressed. The system response to this alarm (module HVAC automatically switches to maximum air changes) should not be suppressed either. 2. Modify the "Return to Service" section of the energy isolation procedure to include a step to notify the Board Operator and Lead Operator prior to returning to service. 3. Modify the "Return to Service" section of the energy isolation procedure to include a step to "leak test the system with nitrogen" prior to placing in service. 4. Modify the "Return to Service" section of the energy isolation form to include a step to "ensure that all safety systems are back to normal" prior to placing in service. 5. Review the Facility Restart Checklist to determine whether any on the checklist items on it would be appropriate to include in the "Return To Service" section of the energy isolation procedure. 6. AES Interior hydro test SOP revised to address identification of all valves, bleeds points, etc…exercised during procedure. SOP changes to be communicated to the work force. 7. EIP development process to be reviewed in toolbox meetings with Operations personnel. |
| 2/21/2008 | CD1 | 840 | 100% Diesel | During frac job, master valve not fully closed and tank overflowed. ½ gal spilled outside of secondary containment. | Fittings/seals/conn ections | Overfill | Structural/ Mechanical | Replaced fittings and reviewed potential reasons for camlock failure. Management is replacing the wire closures to prevent reoccurrence. |

## TABLE C-1 (CONTINUED): ALPINE HISTORY OF OIL SPILLS GREATER THAN 55 GALLONS

| Date | Location | Volume (Gal) | Product | Cause Explanation | Source | General Cause | General Cause Category | Corrective Action |
|---|---|---|---|---|---|---|---|---|
| 3/5/2008 | CD3 | 84 | 70% Produced Water, 30% Hydrocarbon Mixture | Camlok hose fitting failure | Tanks | Equipment Failure | Structural/ Mechanical | An incident investigation will be conducted. |
| 5/17/2008 | CD1 | 170 | 99% Crude oil, 1% Produced Water | Pin hole leak in process piping between slop oil tank and inlet separator. | Pipe/flowlines/hardlines | Corrosion | Structural/ Mechanical | 1) Repair the known damaged areas with temporary clamps. 2) Design and install long term repair for this segment of pipe. 3) Assess the integrity of the remainder of the slop oil system. 4) Assess if similar systems at alpine exist and address as appropriate. 5) Review and update bases of design for new projects and associated engineering specifications to address the routing or disposal of off-specification fluids, in order to isolate the fluids from process piping and equipment. Review and update engineering specifications to address piping systems in off specification fluid handling service. 6) Write a corrosion mitigation procedure to address off specification fluid handling in the Kuparuk and alpine facilities. |
| 7/2/2008 | CD2 | 84 | 100% Crude oil | Employee was rigging up to pump crude returns from a 500-gallon tiger tank to production. Employee was connecting a hose to the flowback tank and pulled a 2" fitting from a suction line. As he pulled one of the ears back on the camlock, it began to leak, and it was determined that an upstream block valve was in the open position. The tank valve did not have a handle on it, and the employee did not verify the position of the valve before pulling the cam-lock cap. Initially all of the spilled material was in secondary containment. When the tank was demobed and the secondary containment removed, employees discovered that the containment had holes, and 8 gallons had leaked through to the gravel pad below. | Tanks | Human Error | Human Factors | All tiger tanks will be inspected prior to being used to make sure they are fully functional and have handles. All tiger tank valves will need to have handles prior to opening them. Supervisor shall review the fluid transfer procedures and check list with employees. Employees will use fluid transfer procedures check list. |

## TABLE C-1 (CONTINUED): ALPINE HISTORY OF OIL SPILLS GREATER THAN 55 GALLONS

| Date | Location | Volume (Gal) | Product | Cause Explanation | Source | General Cause | General Cause Category | Corrective Action |
|---|---|---|---|---|---|---|---|---|
| 5/22/2010 | CD1 | 62 | 100% Hydraulic fluid | It is believed that ice and snow pushed up on the quick connect fitting rereleasing the oil. | Coiled tubing unit/wireline equip/well service | Leak | Structural/ Mechanical | The unit will be on a set inspection schedule once / 3 weeks with a developed check list, the unit will be kept in full containment. All 4 source valves will be left in the closed position, a start up/ shutdown checklist will be developed for the spooling unit, a bulk head will be installed to dry connect the hoses for storage. This will block off the ends from activation and ensure they stay clean. An updated diagram of the unit will be developed and the crews made aware of it. |
| 3/16/2013 | CD1 A7 Produced water handling | 1559.8 | 100% Produced water | A RUPTURED GASKET ON THE DISCHARGE OF THE SAND-JET SLURRY PUMP IN THE ALPINE CFA7 SAND-JET MODULE RESULTED IN A SPILL OF PRODUCED WATER. FAILURE OF MULTIPLE SUMP LEVEL SWITCHES CAUSE THIS WATER TO OVERWHELM THE CFA7 MODULE SUMP, THE CFG4 "LAST CHANCE" SUMP AND ALLOWED A FRACTION OF THE FLUID TO FLOW INTO THE ACF TANK FARM SECONDARY CONTAINMENT. WHEN THE CFG4 SUMP WAS OVERWHELMED, APPROXIMATELY 4 GALLONS OF RESIDUAL OIL WAS DISPLACED AND WAS ALSO SPILLED INTO THE ACF TANK FARM SECONDARY CONTAINMENT. AS ALL OF THE AUTOMATIC SAFETY SYSTEMS TO PREVENT SUCH AN OVERFLOW EVENT HAD FAILED, OPERATOR INTERVENTION WAS REQUIRED TO PREVENT FURTHER ESCALATION OF THE SPILL. | Flanges | Equipment Failure | Structural/ Mechanical | THE FOLLOWING ACTION ITEMS CAME OUT OF HT EINVESTIGATION: 1.MODIFY A7 SANDJET PUMP PIPING TO REMOVE OVERSTRESS SCENARIO 2.EXTEND G5 DISCHARGE PIPING INSULATION AND HEAT TRACE 3.FLUSH THE 6¿ DIAMETER PIPE FROM A7 TO G4 WITH DIESEL TO MITIGATE POTENTIAL CORROSION ISSUES ASSOCIATED WITH PRODUCED WATER CONTAMINATION 4.INVESTIGATE THE BOLT-UP FAILURE ON THE A7 SANDJET SLURRY PUMP 5.REDESIGN THE LEVEL INSTRUMENTATION OF THE A7 MODULE SUMP TO PROVIDE MORE RELIABLE INDICATION 6.INVESTIGATE THE FAILURE OF THE LEAK DETECTION STRIPS 7.EXTEND SUMP LEVEL INDICATION MODIFICATIONS TO A1, A2, A3, A4, AND E2 MODULES RESULTS AS OF 2 APRIL 2013, ACTION ITEMS 1-6 ARE COMPLETE AND ACTION ITEM 7 IS UNDERWAY. LEAK DETECT STRIP CONFIGURATION WAS MODIFIED FROM ALARMING ONLY WHEN "WET" TO ALARM WHEN THE STRIP DETECTS LIQUID OR REGISTERS AS "DIRTY." THIS CHANGE WAS CASCADED TO ALL INSTALLATIONS OF THIS MODEL OF LEAK DETECTION. BOLT-UP PROCEDURES FOR PUMP INSTALLATION WERE REVIEWED WITH MECHANICS TO ENSURE THAT THEY WILL BE FOLLOWED. DESIGN WORK IS ONGOING FOR ACTION ITEM 7 TO INSTALL GUIDED WAVE RADAR STYLE LEVEL INDICATION IN A1, A2, A3, A4, AND E2 MODULES TO MATCH THE NEW INSTALLATION IN THE A7 MODULE. |

## TABLE C-1 (CONTINUED): ALPINE HISTORY OF OIL SPILLS GREATER THAN 55 GALLONS

| Date | Location | Volume (Gal) | Product | Cause Explanation | Source | General Cause | General Cause Category | Corrective Action |
|---|---|---|---|---|---|---|---|---|
| 5/19/2013 | CD1 ACF | 265 | 100% Motor Oil | THE LUBE OIL PUMP BREAKER WAS NOT PROPERLY ISOLATED WHILE THE E2 TURBINE WAS DOWN FOR MAINTENANCE WHICH ALLOWED AN INADVERTENT START TO THE SYSTEM. WHEN THE PUMP KICKED ON THE LUBE OIL RESERVOIR WAS PUMPED TO MINIMUM LEVELS AND SPILLED INTO AND OVERFLOWED THE MODULE SUMPS ONTO THE MODULE FLOOR. | Tanks | Human Error | Human Factors | MANAGEMENT WILL BE CLEARLY OUTLINING EXPECTATIONS RELATED TO ENERGY ISOLATIONS, COMMUNICATE THE LESSON'S LEARNED FROM THE EVENT AND EXPAND AUDITS TO INCREASE FOCUS ON ENERGY ISOLATION AND PROPER VERIFICATIONS OF ENERGY ISOLATIONS. |
| 12/20/2013 | CD1 Tank Farm | 3150 | 50% Diesel, 50% Water/Tank Bottoms/Crude | OPERATOR PUMPED WATER INTO DIESEL TANK INSTEAD OF WATER TANK CAUSING THE DIESEL TANK TO OVERFLOW. | Tanks | Overfill | Human Factors | MI CHANGED OUT THE PIPING ON THE TANKS SO THAT THERE IS A DIRECT FEED INTO THE WATER TANK AND A SEPARATE DIRECT FEED INTO THE DIESEL TANK. MI CHANGED THE DIESEL TANK FILL NOZZLE SO THAT ONLY A DIESEL TRUCK CAN ATTACHED TO THE FILL LINE, A VACUUM TRUCK OR WATER TRUCK CAN NO LONGER ATTACHED TO THE DIESEL LINE. MI PLACED SIGNS ON THE TANKS AND FILL LINES TO DIFFERENTIATE BETWEEN THE WATER AND DIESEL. MI CHANGE THEIR FLUID TRANSFER PROCEDURES TO INCLUDE WATER TRANSFERS. MI WILL USE A SUPERVISOR OR THIRD PERSON WHEN TRAINING EMPLOYEES ON NEW TASKS THAT INVOLVE FLUID TRANSFERS. IT IS DIFFICULT TO TRAIN ON FLUID TRANSFERS WHEN BOTH EMPLOYEES ( THERE IS USUALLY ONLY TWO ON SITE AT A TIME) NEED TO BE WATCHING THE LINES AND ENGAGED WHILE THE FLUID IS BEING TRANSFERRED. THIS LENDS TO BETTER TRAINING. MI HAS COMMITED TO KEEP INDIVIDUALS ON SITE, WHO ARE TRAINED TO THE TASK OF FLUID TRANSFERS, AND NOT HAVE THEM TRANSFERRED TO A NEW POSITION AS OFTEN, RESULTING IN LESS TURN OVER AROUND FOR THIS IMPORTANT TASK. |

## TABLE C-1 (CONTINUED): ALPINE HISTORY OF OIL SPILLS GREATER THAN 55 GALLONS

| Date | Location | Volume (Gal) | Product | Cause Explanation | Source | General Cause | General Cause Category | Corrective Action |
|---|---|---|---|---|---|---|---|---|
| 4/6/2014 | CD3 | 200 | 100% Hydraulic fluid | DURING BLOW OUT PREVENTER MAINTENANCE, PRESSURE WAS BEING BLED OFF ACCUMULATOR BOTTLE TO A TANK. THE TANK DID NOT VENT PROPERLY RESULTING IN RUPTURING THE TANK AND RELEASING HYDRAULIC OIL. | Tanks | Equipment Failure | Structural/ Mechanical | THE TANK WAS REPAIRED AND THE VENT ENLARGED SO PRESSURE WOULD NOT BUILD UP. CONTAINMENT WAS WELDED AROUND THE TANK THAT WOULD CONTAIN ALL OF THE OIL IN THE TANK. ALL OF THE TANKS ON THE RIG HAVE BEEN SLOTTED TO BE INSPECTED FOR CONTAINMENT AND VENT SIZE. THE LESSONS LEARNED WENT OUT TO THE WHOLE DOYON COMPANY. ACCUMULATOR EQUIPMENT ON OTHER DOYON RIGS ARE BEING INSPECTED FOR PROPER VENTS AND CONTAINMENT. |
| 2/18/2015 | CD3 | 126 | 100% Diesel | THE OPEN TOP TANK WAS RATED AT 400BBL AND WAS FILLED BASED ON THAT CAPACITY, HOWEVER THE TANK HAD A HOLE IN IT, MAKING THE MAXIMUM CAPACITY 375BBL. THE TANK WAS NOT RERATED AT THE NEW VOLUME OR REMARKED TO SHOW A REDUCED CAPACITY. | Tanks | Overfill | Human Factors | FORMAL INVESTIGATION COMPLETED. CORRECTIVE ACTIONS ARE: 1)INSPECT ALL OPEN TOP TANKS IN ALP FLEET TO ENSURE THEY ARE EFFECTIVELY LABELED. 2)EVALUATE AND MAKE RECOMMENDATIONS REGARDING THE USE OF PORTABLE LEVEL DETECTION DEVICES. 3)PERFORM AN MOC TO CLOSE ANY HOLES IN SIDE WALL OF OPEN TOP TANKS THAT REDUCE TANK CAPACITY. 4)VERIFY TANK STRAP ACCURACY AND REMOVE INTERNAL STRAPPING MARKINGS THAT ARE CURRENTLY LOCATED ABOVE MAXIMUM ALLOWABLE LEVEL TO REDUCE TANK CAPACITY CONFUSION. 5)EVALUATE THE FEASIBILTY OF INSTALLING A MICRO-MOTION BARREL COUNTER SYSTEM ON CHOKE TO ASSIST IN TRACKING RETURN VOLUMES. 6)EVALUATE REPLACING CURRENT TANKS. 7)DISCUSS THE IMPORTANCE OF DEFINING SPECIFIC EMPLOYEE ROLES AND RESPONSIBILITIES DURING PRE JOB MEETINGS. 8)EVALUATE FEASIBILITY TO CROSS-TRAIN SUPPORTING WORK GROUPS ON CTU OPERATIONS. 9)SLB TO DEVELOP AND INCORPORATE A STANDARDIZED FLUID TRACKING SYSTEM FOR CTU OPERATORS. 10)COMMUNICATE CPAI 90% MAXIMUM TANK LEVEL POLICY TO ALL CPAI WELLS GROUP SUPERVISORS AND TO ALL WELLS SERVICE CONTRACTORS. |

## TABLE D-1
## ALPINE OIL STORAGE TANKS 10,000 GALLONS OR GREATER

| TAG NO. | LOCATION | MODULE | DESCRIPTION | FABRICATION / INSTALLATION DATE | CONSTRUCTION STANDARD | NOMINAL DESIGN CAPACITY (BBL) | PRODUCT TYPE | SECONDARY CONTAINMENT DESCRIPTION | SECONDARY CONTAINMENT VOLUME (BBL) | LIQUID LEVEL MECHANISM | LAST; NEXT EXTERNAL INSPECTION | LAST; NEXT INTERNAL INSPECTION |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| CD2-T-51001 | CD2 | CD2 tank farm | 500 bbl production chemical tank | 1999 | API 12F (11th Edition) | 500 | Crude Oil | Liner supported by concrete | 1,000 | DP | 2016; 2021 | 2011; 2021 |
| CD3-T-383003 | CD3 | CD3J | Hydrocarbon recycle | 2005/2006 | API-650 | 443 | Oil and water | Liner in gravel berm | 860 | DP, Radar | 2016; 2021 | 2016; 2026 |
| CD3-T-513006 | CD3 | CD3J | 443 bbl Vertical | 2005 | API 650 Appendix E & J | 443 | Corrosion Inhibitor | Liner in gravel berm | 860 | Radar, DP | 2015; 2020 | 2010; 2020 |
| CD3-T-553003 | CD3 | CD3J | Water recycle | 2005/2006 | API 650 | 443 | Contaminated water | Liner in gravel berm | 860 | DP, Radar | 2016; 2021 | 2016; 2026 |
| CD3-T-613012 | CD3 | CD3J | AHF tank | 2005/2006 | API 650 | 252 | AHF | Liner in gravel berm | 860 | DP, Radar | 2016; 2021 | 2016; 2026 |
| CD5-T-505031 | CD5 | CD5Q | Weathered Crude tank | 2017/2018 | API 650 Appendix J | 847 | Weathered Crude Oil | Liner supported by concrete wall | 1,170 | Radar | new 2018; 2023 | new 2018; 2028 |
| CF-T-31010 | ACF | G2 | 1,500 bbl Slop Oil Tank | 1998/2000 | API 12D (9th Edition) | 1,500 | Crude/Water | Basin lined with impermeable membrane and coated geotextile layer with sump. | 17,000 | DP, Radar, UT | 2013; 2018 | 2008; 2018 |
| CF-T-50001 | ACF | G2 | 750 bbl production chemical tank | 1998/1999 | API 12D (9th Edition) | 750 | Diesel | Basin lined with impermeable membrane and coated geotextile layer with sump. | 17,000 | Radar | 2015; 2020 | 2010; 2020 |
| CF-T-50061A | ACF | G1 | 400 bbl Completions Fluid Storage Tank | 1998/1999 | API 12F (11th Edition) | 400 | Drilling or Production fluids | Basin lined with impermeable membrane and coated geotextile layer with sump. | 17,000 | Radar | 2014; 2019 | 2014; 2024 |
| CF-T-50061B | ACF | G1 | 400 bbl Completions Fluid Storage Tank | 1998/1999 | API 12F (11th Edition) | 400 | Drilling or Production fluids | Basin lined with impermeable membrane and coated geotextile layer with sump. | 17,000 | Radar | 2014; 2019 | 2014; 2024 |
| CF-T-50090 | ACF | G5 | 803 bbl Vertical | 2003 | API 650 Appendix A & F | 803 | Varies (Diesel or Chemical) | Basin lined with impermeable membrane and coated geotextile layer with sump | 17,000 | DP | 2015; 2020 | 2010; 2020 |

## TABLE D-1
## ALPINE OIL STORAGE TANKS 10,000 GALLONS OR GREATER

| TAG NO. | LOCATION | MODULE | DESCRIPTION | FABRICATION / INSTALLATION DATE | CONSTRUCTION STANDARD | NOMINAL DESIGN CAPACITY (BBL) | PRODUCT TYPE | SECONDARY CONTAINMENT DESCRIPTION | SECONDARY CONTAINMENT VOLUME (BBL) | LIQUID LEVEL MECHANISM | LAST; NEXT EXTERNAL INSPECTION | LAST; NEXT INTERNAL INSPECTION |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| CF-T-51001 | ACF | G2 | 1500 bbl production chemical tank | 1998/2001 | API 650 (modified per 12D) | 1,500 | Dry Crude Oil | Basin lined with impermeable membrane and coated geotextile layer with sump. | 17,000 | Radar, DP | 2015; 2020 | 2010; 2020 |
| CF-T-60001 | ACF | G2 | 250 bbl Lube Oil Storage Tank | 1998/2000 | API 12F (11th Edition) | 250 | Lube Oil | Basin lined with impermeable membrane and coated geotextile layer with sump. | 17,000 | Radar | 2015; 2020 | 2010; 2020 |
| CF-T-61001 | ACF | G1 | 3,300 bbl AHF Storage Tank | 1984/1999 | API 650 Appendix E & F | 3,300 | Misc. hydrocarbon service | Basin lined with impermeable membrane and coated geotextile layer with sump. | 17,000 | DP (note 4) | 2014; 2019 | 2014; 2024 |

1. ACF = Alpine Central Facility
2. DP = Differential pressure
3. UT = Ultrasonic non-contact transmitter
4. Liquid level displayed, and flashing lights with audible alarm are triggered if high levels situation occurs.

## TABLE D-2
## COPA-OWNED PORTABLE OIL STORAGE TANKS 10,000 GALLONS OR GREATER AVAILABLE FOR USE

| TAG NUMBER | TANK DESCRIPTION | VOLUME (BBL) | VOLUME (GAL) | CONTENTS | FABRICATION DATE | CONSTRUCTION STANDARD | LAST; NEXT EXTERNAL INSPECTION | LAST; NEXT INTERNAL INSPECTION | SERVICE HISTORY | COMMENTS |
|---|---|---|---|---|---|---|---|---|---|---|
| AK-2408 | Vertical | 400 | 16,800 | Diesel | 1980 | Closed top/skid | 2017; 2019 | 2017; 2027 | | |
| AP-T-61043 | White hydrocarbon tank (Hector Tank) | 357 | 15,000 | Aviation Jet A fuel | 1998 | ADEC Waiver | 2015; 2020 | 2015; 2025 | | Former Tag CF-T-76004<br>Double-wall, placed in containment<br>ADEC approval, Section 3.11 |
| AP-T-76101 | Upright | 400 | 16,800 | Varies | 2005 | API 650 | 2015; 2020 | 2015; 2023 | | |
| AP-T-76135 | Tiger Tank | 500 | 21,000 | Varies | 2005 | ADEC Approval | 2016; 2021 | 2016; 2026 | | ADEC approval, Section 3.11 |
| AP-T-76137 | Open top Tiger Tank | 400 | 16,800 | Varies | 2005 | ADEC Approval | 2017; 2022 | 2012; 2022 | | ADEC approval, Section 3.11 |
| AP-T-76197 | Open Top | 500 | 21,000 | Varies | 2006 | ADEC Approval | 2013; 2018 | 2013; 2023 | Start 2008 | ADEC approval, Section 3.11 |
| AP-T-76198 | Open Top | 500 | 21,000 | Varies | 2006 | ADEC Approval | 2016; 2021 | 2016; 2026 | | ADEC approval, Section 3.11 |
| AP-T-76223 | Upright | 400 | 16,800 | Varies | 2007 | API 650 App J | 2017; 2022 | 2017; 2027 | | |
| AP-T-76224 | Upright | 400 | 16,800 | Varies | 2007 | API 650 App J | 2017; 2022 | 2012; 2022 | | |
| AP-T-76225 | Upright | 400 | 16,800 | Varies | 2007 | API 650 App J | 2017; 2022 | 2017; 2027 | | |
| AP-T-76350 | Upright | 400 | 16,800 | Varies | 2009 | API 650 | 2017; 2022 | 2017; 2027 | New 2009 | |
| AP-T-76351 | Upright | 400 | 16,800 | Varies | 2009 | API 650 | 2014; 2019 | 2014; 2024 | New 2009 | |
| AP-T-76352 | Tiger Tank | 500 | 21,000 | Varies | 2009 | ADEC Approval | 2014; 2019 | 2014; 2024 | New 2009 | ADEC approval, Section 3.11 |
| AP-T-76362 | Double-wall upright | 400 | 16,800 | Varies | 2008 | API 12F | 2014; 2019 | 2014; 2024 | New 2009 | |
| AP-T-76363 | Double-wall upright | 400 | 16,800 | Varies | 2008 | API 12F | 2014; 2019 | 2014; 2024 | New 2009 | |

## TABLE D-2
## COPA-OWNED PORTABLE OIL STORAGE TANKS 10,000 GALLONS OR GREATER AVAILABLE FOR USE

| TAG NUMBER | TANK DESCRIPTION | VOLUME (BBL) | VOLUME (GAL) | CONTENTS | FABRICATION DATE | CONSTRUCTION STANDARD | LAST; NEXT EXTERNAL INSPECTION | LAST; NEXT INTERNAL INSPECTION | SERVICE HISTORY | COMMENTS |
|---|---|---|---|---|---|---|---|---|---|---|
| AP-T-76364 | Double-wall upright | 400 | 16,800 | Varies | 2008 | API 12F | 2014; 2019 | 2014; 2024 | New 2009 | |
| AP-T-76393 | Double-wall upright | 400 | 16,800 | Varies | 2009 | API 12F | 2014; 2019 | 2014; 2024 | | |
| AP-T-76394 | Double-wall upright | 400 | 16,800 | Varies | 2009 | API 12F | 2014; 2019 | 2014; 2024 | | |
| AP-T-76395 | Double-wall upright | 400 | 16,800 | Varies | 2009 | API 12F | 2014; 2019 | 2014; 2024 | | |
| AP-T-76396 | Double-wall upright | 400 | 16,800 | Varies | 2009 | API 12F | 2014; 2019 | 2014; 2024 | | |
| AP-T-76397 | Double-wall upright | 400 | 16,800 | Varies | 2009 | API 12F | 2014; 2019 | 2014; 2024 | | |
| AP-T-76446 | Tiger Tank | 500 | 21,000 | Varies | 2014 | ADEC Approval | 2015; 2020 | 2015; 2025 | Start of service 2015 | ADEC approval, Section 3.11 |
| AP-T-76447 | Tiger Tank | 500 | 21,000 | Varies | 2014 | ADEC Approval | 2015; 2020 | 2015; 2025 | Start of service 2015 | ADEC approval, Section 3.11 |
| CF-T-76004 | Horizontal open top | 400 | 16,800 | Misc. hydrocarbon service | ND | ADEC Approval | 2014; 2019 | 2014; 2024 | | ADEC approval, Section 3.11 |
| CF-T-76005 | Horizontal open top | 400 | 16,800 | Misc. hydrocarbon service | ND | ADEC Approval | 2017; 2022 | 2017; 2027 | | ADEC approval, Section 3.11 |
| CF-T-76006 | Black Tiger Tank | 450 | 18,900 | Well bore fluids | 2000 | ADEC Approval | 2014; 2019 | 2014; 2024 | | ADEC approval, Section 3.11 |
| CF-T-76007 | Black Tiger Tank | 450 | 18,900 | Well bore fluids | 2000 | ADEC Approval | 2013; 2018 | 2013; 2023 | | ADEC approval, Section 3.11 |
| CF-T-76017 | Gray Upright | 500 | 21,000 | Multi-use, potential hydrocarbons | 1998 | API 12 F (11th Edition) | 2017; 2022 | 2017; 2027 | | |
| CF-T-76033 | Gray Upright | 400 | 16,800 | Misc. hydrocarbon service | 2003 | API 650 | 2017; 2022 | 2012; 2022 | | |
| CF-T-76070 | Brown Open Top | 500 | 21,000 | Misc. hydrocarbon service | 2003 | API 650 | 2014; 2019 | 2014; 2019 | | |
| CF-T-76071 | Brown Tiger Tank | 500 | 21,000 | Misc. hydrocarbon service | 2003 | API 650 | 2013; 2018 | 2013; 2023 | | |

## TABLE D-2
## COPA-OWNED PORTABLE OIL STORAGE TANKS 10,000 GALLONS OR GREATER AVAILABLE FOR USE

| TAG NUMBER | TANK DESCRIPTION | VOLUME (BBL) | VOLUME (GAL) | CONTENTS | FABRICATION DATE | CONSTRUCTION STANDARD | LAST; NEXT EXTERNAL INSPECTION | LAST; NEXT INTERNAL INSPECTION | SERVICE HISTORY | COMMENTS |
|---|---|---|---|---|---|---|---|---|---|---|
| CF-T-76210 | Upright | 400 | 16,800 | Brine, potential hydrocarbons | 2004 | API 650 App J | 2014; 2019 | 2014; 2024 | | |
| CF-T-76819 | Upright | 400 | 16,800 | Misc. hydrocarbon service | 2002 | API 650 (10th Edition) | 2017; 2022 | 2017; 2027 | | |
| CF-T-76820 | Upright | 400 | 16,800 | Misc. hydrocarbon service | 2002 | API 650 (10th Edition) | 2017; 2018 | 2017; 2018 | | |
| DEG-8691 | Vertical | 400 | 16,800 | Diesel | 1984 | Closed top/skid | 2015; 2020 | 2015; 2030 | | |
| DEG-8692 | Vertical | 400 | 16,800 | Diesel | 1984 | Closed top/skid | 2013; 2018 | 2013; 2018 | | |
| DEG-8693 | Vertical | 400 | 16,800 | Varies | 1983 | Closed top/skid | 2017; 2022 | 2017; 2022 | | |
| KP-4132 | Horizontal | 242 | 10,164 | Varies | ND | Open top/skid | 2014; 2019 | 2009; 2019 | | |
| KSP-0511 | Tiger Tank | 500 | 21,000 | Varies | 1992 | Closed top/wheels | 2014; 2019 | 2009; 2019 | | |
| PGE-86AD | Vertical cylinder | 400 | 16,800 | Varies | 1981 | Closed top/skid | 2013; 2018 | 2013; 2018 | | |
| PGE-86AH | Vertical | 400 | 16,800 | Varies | 1984 | Closed top/skid | 2014; 2018 | 2014; 2018 | | |
| PGE-86AI | Vertical | 400 | 16,800 | Varies | 1984 | Closed top/skid | 2013; 2018 | 2013; 2023 | | |
| PGE-86AN | Vertical | 400 | 16,800 | Varies | 1984 | Closed top/skid | 2016; 2018 | 2013; 2023 | | |
| PGE-86AR | Vertical | 400 | 16,800 | Varies | 1984 | Closed top/skid | 2013; 2018 | 2008; 2028 | | |
| PGE-86AW | Vertical | 400 | 16,800 | Varies | 1984 | Closed top/skid | 2014; 2019 | 2004; 2024 | | |
| PGE-86AZ | Vertical | 400 | 16,800 | Varies | 1984 | Closed top/skid | 2014; 2019 | 2004; 2024 | | |
| PGE-86BC | Horizontal cylinder | 400 | 16,800 | Varies | 1985 | Open top/skid | 2016; 2021 | 2016; 2026 | | |

TABLE D-2

COPA-OWNED PORTABLE OIL STORAGE TANKS 10,000 GALLONS OR GREATER AVAILABLE FOR USE

| TAG NUMBER | TANK DESCRIPTION | VOLUME (BBL) | VOLUME (GAL) | CONTENTS | FABRICATION DATE | CONSTRUCTION STANDARD | LAST; NEXT EXTERNAL INSPECTION | LAST; NEXT INTERNAL INSPECTION | SERVICE HISTORY | COMMENTS |
|---|---|---|---|---|---|---|---|---|---|---|
| PGE-86BD | Horizontal cylinder | 400 | 16,800 | Varies | 1985 | Open top/skid | 2015; 2020 | 2010; 2020 | | |
| PGE-86BE | Vertical | 400 | 16,800 | Varies | 1985 | Closed top/skid | 2014; 2019 | 2004; 2024 | | |
| PGE-86BG | Vertical | 400 | 16,800 | Varies | 1985 | Closed top/skid | 2013; 2018 | 2013; 2023 | | |
| PGE-86CE | Vertical cylinder | 400 | 16,800 | Varies | 1985 | Closed top/skid | 2013; 2018 | 2008; 2028 | | |
| PGE-86CF | Vertical cylinder | 400 | 16,800 | Varies | 1985 | Closed top/skid | 2013; 2018 | 2008; 2028 | | |
| PGE-87 | Horizontal cylinder | 400 | 16,800 | Varies | 1984 | Open top/skid | 2013; 2018 | 2013; 2018 | | |
| PGE-87AC | Horizontal cylinder | 400 | 16,800 | Varies | ND | Open top/skid | 2015; 2020 | 2015; 2025 | | |
| PGE-87AD | Horizontal | 400 | 16,800 | Varies | ND | Open top/skid | 2016; 2021 | 2016; 2021 | | |
| SST-001 | Vertical | 400 | 16,800 | Varies | 2000 | API 650 | 2016; 2021 | 2011; 2021 | | |
| SST-002 | Vertical | 400 | 16,800 | Varies | 2000 | API 650 | 2016; 2021 | 2011; 2021 | | non-hydrocarbon service |
| SST-003 | Vertical | 400 | 16,800 | Varies | 2001 | API 650 | 2016; 2021 | 2011; 2021 | | |
| SST-004 | Vertical | 400 | 16,800 | Varies | 2001 | API 650 | 2016; 2021 | 2011; 2021 | | |
| SST-005 | Vertical | 400 | 16,800 | Varies | 2001 | API 650 | 2016; 2021 | 2011; 2021 | | |
| SST-006 | Vertical | 400 | 16,800 | Varies | 2001 | API 650 | 2016; 2021 | 2011; 2021 | | |
| SST-007 | Vertical | 400 | 16,800 | Varies | 2001 | API 650 | 2016; 2021 | 2011; 2021 | | |
| SST-008 | Vertical | 400 | 16,800 | Varies | 2001 | API 650 | 2016; 2021 | 2011; 2021 | | |
| SST-009 | Vertical | 400 | 16,800 | Varies | 2001 | API 650 | 2016; 2019 | 2011; 2021 | | |

TABLE D-2
COPA-OWNED PORTABLE OIL STORAGE TANKS 10,000 GALLONS OR GREATER AVAILABLE FOR USE

| TAG NUMBER | TANK DESCRIPTION | VOLUME (BBL) | VOLUME (GAL) | CONTENTS | FABRICATION DATE | CONSTRUCTION STANDARD | LAST; NEXT EXTERNAL INSPECTION | LAST; NEXT INTERNAL INSPECTION | SERVICE HISTORY | COMMENTS |
|---|---|---|---|---|---|---|---|---|---|---|
| SST-010 | Vertical | 400 | 16,800 | Varies | 2001 | API 650 | 2016; 2021 | 2011; 2021 | | |
| SST-015 | Horizontal Steelfab Flowback | 400 | 16,800 | Varies | 2006 | ADEC BBFM-205126-09/05 UL 142 | 2016; 2021 | 2016; 2021 | | Double-wall, tank-within-tank design |
| SST-016 | Horizontal Steelfab Flowback | 400 | 16,800 | Varies | 2006 | ADEC BBFM-205126-09/05 UL 142 | 2016; 2021 | 2016; 2021 | | Double-wall, tank-within-tank design |
| SST-017 | Horizontal Steelfab Flowback | 400 | 16,800 | Varies | 2006 | ADEC BBFM-205126-09/05 UL 142 | 2016; 2021 | 2016; 2021 | | Double-wall, tank-within-tank design |
| SST-018 | Horizontal Steelfab Flowback | 400 | 16,800 | Varies | 2006 | ADEC BBFM-205126-09/05 UL 142 | 2016; 2021 | 2016; 2021 | | Double-wall, tank-within-tank design |
| SST-019 | Horizontal Steelfab Flowback | 400 | 16,800 | Varies | 2006 | ADEC BBFM-205126-09/05 UL 142 | 2016; 2021 | 2016; 2021 | | Double-wall, tank-within-tank design |
| SST-020 | Horizontal Steelfab Flowback | 400 | 16,800 | Varies | 2006 | ADEC BBFM-205126-09/05 UL 142 | 2016; 2021 | 2016; 2021 | | Double-wall, tank-within-tank design |
| SST-027 | Horizontal Steelfab Flowback | 400 | 16,800 | Varies | 2007 | ADEC BBFM-205126-09/05 UL 142 | 2013; 2018 | 2013; 2018 | | Double-wall, tank-within-tank design |
| SST-028 | Horizontal Steelfab Flowback | 400 | 16,800 | Varies | 2007 | ADEC BBFM-205126-09/05 UL 142 | 2013; 2018 | 2013; 2018 | | Double-wall, tank-within-tank design |
| SST-029 | Horizontal Steelfab Flowback | 400 | 16,800 | Varies | 2007 | ADEC BBFM-205126-09/05 UL 142 | 2017; 2022 | 2012; 2022 | | Double-wall, tank-within-tank design |
| SST-065 | Horizontal Steelfab Flowback | 400 | 16,800 | Varies | 2009 | ADEC BBFM-205126-09/05 UL 142 | 2014; 2019 | 2014; 2019 | New 2009 | Double-wall, tank-within-tank design |
| SST-066 | Horizontal Steelfab Flowback | 400 | 16,800 | Varies | 2009 | ADEC BBFM-205126-09/05 UL 142 | 2014; 2019 | 2014; 2019 | New 2009 | Double-wall, tank-within-tank design |
| SST-067 | Horizontal Steelfab Flowback | 400 | 16,800 | Varies | 2009 | ADEC BBFM-205126-09/05 | 2015; 2020 | 2015; 2020 | New 2009 | Double-wall, tank-within-tank design |

## TABLE D-2

## COPA-OWNED PORTABLE OIL STORAGE TANKS 10,000 GALLONS OR GREATER AVAILABLE FOR USE

| TAG NUMBER | TANK DESCRIPTION | VOLUME (BBL) | VOLUME (GAL) | CONTENTS | FABRICATION DATE | CONSTRUCTION STANDARD | LAST; NEXT EXTERNAL INSPECTION | LAST; NEXT INTERNAL INSPECTION | SERVICE HISTORY | COMMENTS |
|---|---|---|---|---|---|---|---|---|---|---|
| SST-071 | Horizontal Steelfab Flowback | 400 | 16,800 | Varies | 2010 | ADEC BBFM-205126-09/05 UL 142 | 2015; 2020 | 2015; 2020 | New 2010 | Double-wall, tank-within-tank design |
| SUR-001 | Double-wall upright | 400 | 16,800 | Varies | 2007 | API 12F | 2017; 2022 | 2017; 2027 | | Former ID Atigun 250 |
| SUR-002 | Double-wall upright | 400 | 16,800 | Varies | 2007 | API 12F | 2017; 2022 | 2017; 2027 | | Former ID Atigun 251 |
| SUR-003 | Double-wall upright | 400 | 16,800 | Varies | 2008 | API 12F | 2013; 2018 | 2013; 2018 | | Former ID Atigun 286 |
| SUR-004 | Double-wall upright | 400 | 16,800 | Varies | 2008 | API 12F | 2013; 2018 | 2013; 2018 | | Former ID Atigun 287 |
| SUR-005 | Double-wall upright | 400 | 16,800 | Varies | 2008 | API 12F | 2013; 2018 | 2013; 2018 | | Former ID Atigun 306 |
| SUR-006 | Double-wall upright | 400 | 16,800 | Varies | 2008 | API 12F | 2013; 2018 | 2013; 2018 | | Former ID Atigun 303 |
| SUR-007 | Double-wall upright | 400 | 16,800 | Varies | 2014 | API 12F | 2015; 2020 | 2015; 2025 | Start of service 2015 | |
| SUR-008 | Double-wall upright | 400 | 16,800 | Varies | 2014 | API 12F | 2015; 2020 | 2015; 2025 | Start of service 2015 | |
| SUR-009 | Double-wall upright | 400 | 16,800 | Varies | 2014 | API 12F | 2015; 2020 | 2015; 2025 | Start of service 2015 | |
| SUR-010 | Double-wall upright | 400 | 16,800 | Varies | 2014 | API 12F | 2015; 2020 | 2015; 2025 | Start of service 2015 | |
| SUR-011 | Double-wall upright | 400 | 16,800 | Varies | 2014 | API 12F | 2015; 2020 | 2015; 2025 | Start of service 2015 | |
| SUR-012 | Double-wall upright | 400 | 16,800 | Varies | 2014 | API 12F | 2015; 2020 | 2015; 2025 | Start of service 2015 | |
| SUR-013 | Double-wall upright | 400 | 16,800 | Varies | 2014 | API 12F | 2015; 2020 | 2015; 2025 | Start of service 2015 | |
| SUR-014 | Double-wall upright | 400 | 16,800 | Varies | 2014 | API 12F | 2015; 2020 | 2015; 2025 | Start of service 2015 | |
| SUR-015 | Double-wall upright | 400 | 16,800 | Varies | 2014 | API 12F | 2015; 2020 | 2015; 2025 | Start of service 2015 | |
| SUR-016 | Double-wall upright | 400 | 16,800 | Varies | 2016 | API 12F | 2016; 2021 | 2016; 2026 | Start of service 2016 | |

## TABLE D-2
## COPA-OWNED PORTABLE OIL STORAGE TANKS 10,000 GALLONS OR GREATER AVAILABLE FOR USE

| TAG NUMBER | TANK DESCRIPTION | VOLUME (BBL) | VOLUME (GAL) | CONTENTS | FABRICATION DATE | CONSTRUCTION STANDARD | LAST; NEXT EXTERNAL INSPECTION | LAST; NEXT INTERNAL INSPECTION | SERVICE HISTORY | COMMENTS |
|---|---|---|---|---|---|---|---|---|---|---|
| SUR-017 | Double-wall upright | 400 | 16,800 | Varies | 2016 | API 12F | 2016; 2021 | 2016; 2026 | Start of service 2016 | |
| SUR-018 | Double-wall upright | 400 | 16,800 | Varies | 2016 | API 12F | 2016; 2021 | 2016; 2026 | Start of service 2016 | |
| SUR-019 | Double-wall upright | 400 | 16,800 | Varies | 2016 | API 12F | 2016; 2021 | 2016; 2026 | Start of service 2016 | |
| SUR-020 | Double-wall upright | 400 | 16,800 | Varies | 2016 | API 12F | 2016; 2021 | 2016; 2026 | Start of service 2016 | |
| SUR-021 | Double-wall upright | 400 | 16,800 | Varies | 2016 | API 12F | 2016; 2021 | 2016; 2026 | Start of service 2016 | |
| T-M101 (SST-011) | Vertical | 400 | 16,800 | Varies | 2005 | API 650 | 2015; 2020 | 2015; 2020 | | |
| T-M102 (SST-012) | Vertical | 400 | 16,800 | Varies | 2005 | API 650 | 2015; 2020 | 2015; 2020 | | |
| T-M103 (SST-013) | Vertical | 400 | 16,800 | Varies | 2005 | API 650 | 2015; 2020 | 2015; 2020 | | |
| T-M104 (SST-014) | Vertical | 400 | 16,800 | Varies | 2005 | API 650 | 2015; 2020 | 2015; 2020 | | |

**Notes:**

1. All listed tanks are welded construction. Tanks are owned and operated by COPA. Tanks named "AP-T" or "CF-T" typically located in Alpine, remaining listed tanks are typically located in Kuparuk, but may be used at other locations, if needed.

2. Skid-mounted tanks rest approximately 1 to 1.5 feet above the ground.

3. ND = No data available.

TABLE D-3

## RENTED OR LEASED PORTABLE OIL STORAGE TANKS 10,000 GALLONS OR GREATER AVAILABLE FOR USE

| OWNER | TAG NUMBER | TANK DESCRIPTION | VOLUME (BBL) | VOLUME (GAL) | CONTENTS | FABRICATION DATE | CONSTRUCTION STANDARD | EXTERNAL INSPECTION LAST; NEXT | INTERNAL INSPECTION LAST; NEXT | SERVICE HISTORY | COMMENTS |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Atigun | 123 | Double-wall, welded steel | 400 | 16,800 | Oil; drilling fluids | 2006 | API 12F | 2016; 2021 | 2016; 2026 | New 2006 | |
| Atigun | 124 | Double-wall, welded steel | 400 | 16,800 | Oil; drilling fluids | 2006 | API 12F | 2013; 2018 | 2013; 2023 | New 2006 | |
| Atigun | 125 | Double-wall, welded steel | 400 | 16,800 | Oil; drilling fluids | 2006 | API 12F | 2016; 2021 | 2016; 2026 | New 2006 | |
| Atigun | 126 | Double-wall, welded steel | 400 | 16,800 | Oil; drilling fluids | 2006 | API 12F | 2016; 2021 | 2016; 2026 | New 2006 | |
| Atigun | 127 | Double-wall, welded steel | 400 | 16,800 | Oil; drilling fluids | 2006 | API 12F | 2016; 2021 | 2016; 2026 | New 2006 | |
| Atigun | 128 | Double-wall, welded steel | 400 | 16,800 | Oil; drilling fluids | 2006 | API 12F | 2015; 2021 | 2015; 2021 | New 2006 | |
| Atigun | 1128 | Horizontal open-top | 253 | 10,660 | Drilling fluids | 2002 | None | 2014; 2019 | 2014; 2024 | | three compartment tank |
| MagTec | 027291-05 | Single wall upright | 400 | 16,800 | Varies; drilling fluids | 2013 | API 12F | New 2013; 2018 | New 2013; 2023 | | |
| MagTec | 027291-09 | Single wall upright | 400 | 16,800 | Varies; drilling fluids | 2013 | API 12F | New 2013; 2018 | New 2013; 2023 | | |
| MagTec | 027503-02 | Single wall upright | 400 | 16,800 | Varies; drilling fluids | 2013 | API 12F | New 2013; 2018 | New 2013; 2023 | | |
| MagTec | 027503-10 | Single wall upright | 400 | 16,800 | Varies; drilling fluids | 2013 | API 12F | New 2013; 2018 | New 2013; 2023 | | |
| MagTec | 603-105 | Single wall upright | 400 | 16,800 | Varies; drilling fluids | 2012 | API 12F | 2017; 2022 | 2012; 2022 | New 2012 | SN 024841-04 |
| MagTec | 603-107 | Single wall upright | 400 | 16,800 | Varies; drilling fluids | 2012 | API 12F | 2017; 2022 | 2012; 2022 | New 2012 | SN 024841-07 |

## TABLE D-3
## RENTED OR LEASED PORTABLE OIL STORAGE TANKS 10,000 GALLONS OR GREATER AVAILABLE FOR USE

| OWNER | TAG NUMBER | TANK DESCRIPTION | VOLUME (BBL) | VOLUME (GAL) | CONTENTS | FABRICATION DATE | CONSTRUCTION STANDARD | EXTERNAL INSPECTION LAST; NEXT | INTERNAL INSPECTION LAST; NEXT | SERVICE HISTORY | COMMENTS |
|---|---|---|---|---|---|---|---|---|---|---|---|
| MagTec | 603-127 | Single wall upright | 400 | 16,800 | Varies; drilling fluids | 2013 | API 12F | 2015; 2020 | 2015; 2025 | New 2013 | SN 024333-10 |
| MagTec | 603-128 | Single wall upright | 400 | 16,800 | Varies; drilling fluids | 2013 | API 12F | 2015; 2020 | 2015; 2025 | New 2013 | SN 026106-06 |
| MagTec | 603-129 | Single wall upright | 400 | 16,800 | Varies; drilling fluids | 2013 | API 12F | 2015; 2020 | 2015; 2025 | New 2013 | SN 026106-07 |
| MagTec | 603-131 | Single wall upright | 400 | 16,800 | Varies; drilling fluids | 2013 | API 12F | New 2013; 2018 | New 2013; 2023 | New 2013 | SN 027291-10 |
| MagTec | 603-133 | Single wall upright | 400 | 16,800 | Varies; drilling fluids | 2013 | API 12F | 2015; 2020 | 2015; 2025 | New 2013 | SN 024333-07 |
| MagTec | 603-135 | Single wall upright | 400 | 16,800 | Varies; drilling fluids | 2013 | API 12F | New 2013; 2018 | New 2013; 2023 | New 2013 | SN 027291-06 |
| MagTec | 603-136 | Single wall upright | 400 | 16,800 | Varies; drilling fluids | 2013 | API 12F | New 2013; 2018 | New 2013; 2023 | New 2013 | SN 027503-04 |
| MagTec | 603-139 | Single wall upright | 400 | 16,800 | Varies; drilling fluids | 2013 | API 12F | 2015; 2020 | 2015; 2025 | New 2013 | SN 024841-14 |
| MagTec | 603-142 | Single wall upright | 400 | 16,800 | Varies; drilling fluids | 2013 | API 12F | 2015; 2020 | 2015; 2025 | New 2013 | SN 024841-11 |
| MagTec | 603-146 | Single wall upright | 400 | 16,800 | Varies; drilling fluids | 2013 | API 12F | 2013; 2018 | 2013; 2023 | New 2013 | SN 027291-05 |
| MagTec | 603-148 | Single wall upright | 400 | 16,800 | Varies; drilling fluids | 2013 | API 12F | 2015; 2020 | 2015; 2025 | New 2013 | SN 026106-03 |
| MagTec | 603-149 | Single wall upright | 400 | 16,800 | Varies; drilling fluids | 2013 | API 12F | 2015; 2020 | 2015; 2025 | New 2013 | SN 026106-04 |
| MagTec | 603-163 | Single wall upright | 400 | 16,800 | Varies; drilling fluids | 2013 | API 12F | 2013; 2018 | 2013; 2023 | New 2013 | SN 030978-01 |

TABLE D-3

RENTED OR LEASED PORTABLE OIL STORAGE TANKS 10,000 GALLONS OR GREATER AVAILABLE FOR USE

| OWNER | TAG NUMBER | TANK DESCRIPTION | VOLUME (BBL) | VOLUME (GAL) | CONTENTS | FABRICATION DATE | CONSTRUCTION STANDARD | EXTERNAL INSPECTION LAST; NEXT | INTERNAL INSPECTION LAST; NEXT | SERVICE HISTORY | COMMENTS |
|---|---|---|---|---|---|---|---|---|---|---|---|
| MagTec | 603-164 | Single wall upright | 400 | 16,800 | Varies; drilling fluids | 2013 | API 12F | 2013; 2018 | 2013; 2023 | New 2013 | SN 030978-02 |
| MagTec | 603-166 | Single wall upright | 400 | 16,800 | Varies; drilling fluids | 2013 | API 12F | 2013; 2018 | 2013; 2023 | New 2013 | SN 030978-04 |
| MagTec | 603-170 | Single wall upright | 400 | 16,800 | Varies; drilling fluids | 2014 | API 12F | 2014; 2019 | 2014; 2024 | New 2014 | SN 031472-02 |
| MagTec | 603-172 | Single wall upright | 400 | 16,800 | Varies; drilling fluids | 2014 | API 12F | 2014; 2019 | 2014; 2024 | New 2014 | SN 031472-04 |
| MagTec | 603-173 | Single wall upright | 400 | 16,800 | Varies; drilling fluids | 2014 | API 12F | 2014; 2019 | 2014; 2024 | New 2014 | SN 031472-05 |
| MagTec | 603-174 | Single wall upright | 400 | 16,800 | Varies; drilling fluids | 2014 | API 12F | 2014; 2019 | 2014; 2024 | New 2014 | SN 031472-06 |
| MagTec | 603-176 | Single wall upright | 400 | 16,800 | Varies; drilling fluids | 2014 | API 12F | 2014; 2019 | 2014; 2024 | New 2014 | SN 030978-06 |
| MagTec | 603-177 | Single wall upright | 400 | 16,800 | Varies; drilling fluids | 2014 | API 12F | 2014; 2019 | 2014; 2024 | New 2014 | SN 031472-08 |
| MagTec | 603-178 | Single wall upright | 400 | 16,800 | Varies; drilling fluids | 2014 | API 12F | 2014; 2019 | 2014; 2024 | New 2014 | SN 030978-10 |
| Rain for Rent | 239578 | Bi-Level Tiger Tank | 500 | 21,000 | Oil; drilling fluids | 1995 | RFR Spec. 99044 | 2017; 2022 | 2012; 2022 | Continuous since 1998 | COPA Ref# SST-024 |
| Rain for Rent | 252826 | Double-wall upright | 400 | 16,800 | Varies | 2014 | API 12F | New 2014; 2019 | New 2014; 2024 | New 2014 | |
| Rain for Rent | 252827 | Double-wall upright | 400 | 16,800 | Varies | 2014 | API 12F | New 2014; 2019 | New 2014; 2024 | New 2014 | |
| Rain for Rent | 252828 | Double-wall upright | 400 | 16,800 | Varies | 2014 | API 12F | New 2014; 2019 | New 2014; 2024 | New 2014 | |

## TABLE D-3
## RENTED OR LEASED PORTABLE OIL STORAGE TANKS 10,000 GALLONS OR GREATER AVAILABLE FOR USE

| OWNER | TAG NUMBER | TANK DESCRIPTION | VOLUME (BBL) | VOLUME (GAL) | CONTENTS | FABRICATION DATE | CONSTRUCTION STANDARD | EXTERNAL INSPECTION LAST; NEXT | INTERNAL INSPECTION LAST; NEXT | SERVICE HISTORY | COMMENTS |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Rain for Rent | 252829 | Double-wall upright | 400 | 16,800 | Varies | 2014 | API 12F | New 2014; 2019 | New 2014; 2024 | New 2014 | |
| Rain for Rent | 252830 | Double-wall upright | 400 | 16,800 | Varies | 2014 | API 12F | New 2014; 2019 | New 2014; 2024 | New 2014 | |
| Rain for Rent | 252832 | Double-wall upright | 400 | 16,800 | Varies | 2014 | API 12F | New 2014; 2019 | New 2014; 2024 | New 2014 | |
| Rain for Rent | 254254 | Bi-Level Tiger Tank | 500 | 21,000 | Varies | 1999 | RFR Spec. 99044 | 2017; 2022 | 2012; 2022 | Continuous since 1999 | |
| Rain for Rent | 254881 | Bi-Level Tiger Tank | 500 | 21,000 | Varies | 2000 | RFR Spec. 99044 | 2014; 2019 | 2012; 2022 | Continuous since 2000 | |
| Rain for Rent | 254993 | Bi-Level Tiger Tank | 500 | 21,000 | Varies | 2000 | RFR Spec. 99044 | 2017; 2022 | 2012; 2022 | Continuous since 2000 | |
| Rain for Rent | 255141 | Bi-Level Tiger Tank | 500 | 21,000 | Varies | 2001 | RFR Spec. 99044 | 2017; 2022 | 2012; 2022 | Continuous since 2001 | |
| Rain for Rent | 255317 | Bi-Level Tiger Tank | 500 | 21,000 | Oil; drilling fluids | 2001 | RFR Spec. 99044 | 2017; 2022 | 2012; 2022 | Continuous since 2001 | COPA Ref# SST-023 |
| Rain for Rent | 255497 | Bi-Level Tiger Tank | 500 | 21,000 | Oil; drilling fluids | 2001 | RFR Spec. 99044 | 2014; 2019 | 2014; 2024 | Continuous since 2001 | COPA Ref# SST-022 |
| Rain for Rent | 255902 | Bi-Level Tiger Tank | 500 | 21,000 | Varies | 2006 | RFR Spec. 107789 | 2015; 2020 | 2010; 2020 | Continuous since 2006 | |
| Rain for Rent | 258119 | Tiger Tank | 500 | 21,000 | Varies | 2000 | RFR Spec. 99044 | 2013; 2018 | 2008; 2018 | Continuous since 2000 | |
| Rain for Rent | 258670 | Bi-Level Tiger Tank | 500 | 21,000 | Varies | 2002 | RFR Spec. 107789 | 2015; 2020 | 2010; 2020 | Continuous since 2002 | |
| Rain for Rent | 259172 | Bi-Level Tiger Tank | 500 | 21,000 | Varies | 2004 | RFR Spec. 107789 | 2015; 2020 | 2010; 2020 | Continuous since 2004 | |
| Rain for Rent | 259408 | Bi-Level Tiger Tank | 500 | 21,000 | Varies | 2004 | RFR Spec. 107789 | 2015; 2020 | 2010; 2020 | Continuous since 2004 | |
| Rain for Rent | 259412 | Bi-Level Tiger Tank | 500 | 21,000 | Varies | 2004 | RFR Spec. 107789 | 2015; 2020 | 2010; 2020 | Continuous since 2004 | |

## TABLE D-3
## RENTED OR LEASED PORTABLE OIL STORAGE TANKS 10,000 GALLONS OR GREATER AVAILABLE FOR USE

| OWNER | TAG NUMBER | TANK DESCRIPTION | VOLUME (BBL) | VOLUME (GAL) | CONTENTS | FABRICATION DATE | CONSTRUCTION STANDARD | EXTERNAL INSPECTION LAST; NEXT | INTERNAL INSPECTION LAST; NEXT | SERVICE HISTORY | COMMENTS |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Rain for Rent | 265402 | Bi-Level Tiger Tank | 500 | 21,000 | Varies | 2006 | RFR Spec. 107789 | 2015; 2020 | 2010; 2020 | Continuous since 2006 | |
| Rain for Rent | 266010 | Tiger Tank | 500 | 21,000 | Varies | 2008 | RFR Spec. 99044 | 2013; 2018 | New 2008; 2018 | New 2008 | |
| TANKO Alaska | 108 | Double-wall, welded steel | 570 | 23,940 | Oil; drilling fluids | 1983 | None | 2014; 2019 | 2014; 2019 | Continuous since 1983 | |
| TANKO Alaska | 111 | Double-wall, welded steel | 570 | 23,940 | Varies | 1983 | None | 2014; 2019 | 2014; 2019 | Continuous since 1983 | COPA Ref# SST-068 |
| TANKO Alaska | 114 | Double-wall, welded steel | 570 | 23,940 | Oil; drilling fluids | 1983 | None | 2014; 2019 | 2014; 2019 | Continuous since 1983 | |
| TANKO Alaska | 115 | Double-wall, welded steel | 570 | 23,940 | Oil; drilling fluids | 1983 | None | 2014; 2019 | 2014; 2019 | Continuous since 1983 | |
| TANKO Alaska | 116 | Double-wall, welded steel | 570 | 23,940 | Oil; drilling fluids | 1983 | None | 2014; 2019 | 2014; 2019 | Continuous since 1992 | COPA Ref# SST-030 |
| TANKO Alaska | 117 | Double-wall, welded steel | 570 | 23,940 | Oil; drilling fluids | 1983 | None | 2014; 2019 | 2014; 2019 | Continuous since 1992 | COPA Ref# SST-031 |
| TANKO Alaska | 118 | Double-wall, welded steel | 570 | 23,940 | Oil; drilling fluids | 1983 | None | 2014; 2019 | 2014; 2019 | Continuous since 1992 | COPA Ref# SST-032 |
| TANKO Alaska | 119 | Double-wall, welded steel | 570 | 23,940 | Oil; drilling fluids | 1983 | None | 2014; 2019 | 2014; 2019 | Continuous since 1992 | COPA Ref# SST-033 |
| TANKO Alaska | 121 | Double-wall, welded steel | 570 | 23,940 | Oil; drilling fluids | 1983 | None | 2014; 2019 | 2014; 2019 | Continuous since 1992 | COPA Ref# SST-034 |
| TANKO Alaska | 122 | Double-wall, welded steel | 570 | 23,940 | Oil; drilling fluids | 1983 | None | 2014; 2019 | 2014; 2019 | Continuous since 1992 | |
| TANKO Alaska | 123 | Double-wall, welded steel | 570 | 23,940 | Oil; drilling fluids | 1983 | None | 2014; 2019 | 2014; 2019 | Continuous since 1983 | |

## TABLE D-3
## RENTED OR LEASED PORTABLE OIL STORAGE TANKS 10,000 GALLONS OR GREATER AVAILABLE FOR USE

| OWNER | TAG NUMBER | TANK DESCRIPTION | VOLUME (BBL) | VOLUME (GAL) | CONTENTS | FABRICATION DATE | CONSTRUCTION STANDARD | EXTERNAL INSPECTION LAST; NEXT | INTERNAL INSPECTION LAST; NEXT | SERVICE HISTORY | COMMENTS |
|---|---|---|---|---|---|---|---|---|---|---|---|
| TANKO Alaska | 124 | Double-wall, welded steel | 570 | 23,940 | Oil; drilling fluids | 1983 | None | 2014; 2019 | 2014; 2019 | Continuous since 1983 | COPA Ref# SST-051 |
| TANKO Alaska | 125 | Double-wall, welded steel | 570 | 23,940 | Oil; drilling fluids | 1983 | None | 2014; 2019 | 2014; 2019 | Continuous since 1983 | COPA Ref# SST-052 |
| TANKO Alaska | 127 | Double-wall, welded steel | 570 | 23,940 | Oil; drilling fluids | 1983 | None | 2014; 2019 | 2014; 2019 | Continuous since 1992 | |
| TANKO Alaska | 128 | Double-wall, welded steel | 570 | 23,940 | Oil; drilling fluids | 1983 | None | 2014; 2019 | 2014; 2019 | Continuous since 1983 | COPA Ref# SST-053 |
| TANKO Alaska | 130 | Double-wall, welded steel | 570 | 23,940 | Oil; drilling fluids | 1983 | None | 2015; 2020 | 2015; 2020 | Continuous since 1983 | |
| TANKO Alaska | 131 | Double-wall, welded steel | 570 | 23,940 | Varies | 1983 | None | 2015; 2020 | 2015; 2020 | Continuous since 1983 | COPA Ref# SST-069 |
| TANKO Alaska | 132 | Double-wall, welded steel | 570 | 23,940 | Oil; drilling fluids | 1983 | None | 2014; 2019 | 2014; 2019 | Continuous since 1983 | |
| TANKO Alaska | H-01 | Single-wall upright | 400 | 16,800 | Varies | 1992 | None | 2016; 2021 | 2016; 2021 | Continuous since 1992 | COPA Ref# SST-036 |
| TANKO Alaska | H-07 | Single-wall upright | 400 | 16,800 | Varies | 1992 | None | 2016; 2021 | 2016; 2021 | Continuous since 1992 | COPA Ref# SST-042 |
| TANKO Alaska | O-3 (CTU-03) | Double-wall; Horizontal open-top | 616 | 25,872 | Varies | 1990 | None | 2015; 2020 | 2015; 2020 | Continuous since 1990 | |
| TANKO Alaska | O-5 (CTU-05) | Double-wall; Horizontal open-top | 461 | 19,362 | Varies | 1990 | None | 2013; 2018 | 2013; 2018 | Continuous since 1990 | |
| TANKO Alaska | O-8 (CTU-08) | Double-wall; Horizontal open-top | 460 | 19,320 | Varies | 1992 | None | 2014; 2019 | 2014; 2019 | Continuous since 1992 | COPA Ref# SST-055 |
| TANKO Alaska | O-9 (CTU-09) | Double-wall; Horizontal open-top | 505 | 21,210 | Varies | 1992 | None | 2016; 2021 | 2016; 2021 | Continuous since 1992 | COPA Ref# SST-056 |

## TABLE D-3
## RENTED OR LEASED PORTABLE OIL STORAGE TANKS 10,000 GALLONS OR GREATER AVAILABLE FOR USE

| OWNER | TAG NUMBER | TANK DESCRIPTION | VOLUME (BBL) | VOLUME (GAL) | CONTENTS | FABRICATION DATE | CONSTRUCTION STANDARD | EXTERNAL INSPECTION LAST; NEXT | INTERNAL INSPECTION LAST; NEXT | SERVICE HISTORY | COMMENTS |
|---|---|---|---|---|---|---|---|---|---|---|---|
| TANKO Alaska | O-10 | Single-wall Open Top Skid | 415 | 17,430 | Varies | Unknown | None | 2015; 2020 | 2015; 2020 | Continuous | |
| TANKO Alaska | O-11 | Single-wall Open Top Skid | 415 | 17,430 | Varies | Unknown | None | 2015; 2020 | 2015; 2020 | Continuous | |
| TANKO Alaska | O-15 | Tiger Tank | 320 | 13,440 | Varies | 1986 | None | 2014; 2019 | 2014; 2019 | Continuous since 1990 | COPA Ref# SST-057 |
| TANKO Alaska | O-16 | Tiger Tank | 320 | 13,440 | Varies | 1986 | None | 2014; 2019 | 2014; 2019 | Continuous since 1990 | COPA Ref# SST-058 |
| TANKO Alaska | O-17 | Tiger Tank | 320 | 13,440 | Varies | Pre-1990 | None | 2015; 2020 | 2015; 2020 | Continuous since 1990 | COPA Ref# SST-044 |
| TANKO Alaska | O-21 | Tiger Tank | 460 | 19,320 | Varies | 1986 | None | 2014; 2019 | 2014; 2019 | Continuous since 1990 | COPA Ref# SST-045 |
| TANKO Alaska | O-22 | Tiger Tank | 500 | 21,000 | Varies | 1986 | None | 2014; 2019 | 2014; 2019 | Continuous since 1990 | |
| TANKO Alaska | O-23 | Tiger Tank | 500 | 21,000 | Varies | 1986 | None | 2014; 2019 | 2014; 2019 | Continuous since 1990 | |
| TANKO Alaska | T-12 | Horizontal open-top | 425 | 17,850 | Varies | Pre-1992 | None | 2013; 2018 | 2013; 2018 | Continuous since 1992 | |
| TANKO Alaska | T-22 | Double-wall Horizontal Open-top | 400 | 16,800 | Drilling fluids | 2013 | ADEC Approval #2014-01 | New; 2018 | New; 2018 | Start of service 2014 | See letter dated 10/27/2014 in Section 3.11 |
| TANKO Alaska | T-23 | Double-wall Horizontal Open-top | 400 | 16,800 | Drilling fluids | 2013 | ADEC Approval #2014-01 | New; 2018 | New; 2018 | Start of service 2014 | See letter dated 10/27/2014 in Section 3.11 |
| TANKO Alaska | T-24 | Double-wall Horizontal Open-top | 400 | 16,800 | Drilling fluids | 2014 | ADEC Approval #2014-01 | New; 2019 | New; 2019 | New 2014 | See letter dated 10/27/2014 in Section 3.11 |
| TANKO Alaska | T-25 | Double-wall Horizontal Open-top | 400 | 16,800 | Drilling fluids | 2014 | ADEC Approval #2014-01 | New; 2019 | New; 2019 | New 2014 | See letter dated 10/27/2014 in Section 3.11 |

# TABLE D-3
## RENTED OR LEASED PORTABLE OIL STORAGE TANKS 10,000 GALLONS OR GREATER AVAILABLE FOR USE

| OWNER | TAG NUMBER | TANK DESCRIPTION | VOLUME (BBL) | VOLUME (GAL) | CONTENTS | FABRICATION DATE | CONSTRUCTION STANDARD | EXTERNAL INSPECTION LAST; NEXT | INTERNAL INSPECTION LAST; NEXT | SERVICE HISTORY | COMMENTS |
|---|---|---|---|---|---|---|---|---|---|---|---|
| TANKO Alaska | T-26 | Double-wall Horizontal Open-top | 400 | 16,800 | Drilling fluids | 2014 | ADEC Approval #2014-01 | New; 2019 | New; 2019 | New 2014 | See letter dated 10/27/2014 in Section 3.11 |
| TANKO Alaska | T-27 | Double-wall Horizontal Open-top | 400 | 16,800 | Drilling fluids | 2014 | ADEC Approval #2014-01 | New; 2019 | New; 2019 | New 2014 | See letter dated 10/27/2014 in Section 3.11 |
| TANKO Alaska | T-28 | Double-wall Horizontal Open-top | 400 | 16,800 | Drilling fluids | 2014 | ADEC Approval #2014-01 | New; 2019 | New; 2019 | New 2014 | See letter dated 10/27/2014 in Section 3.11 |
| TANKO Alaska | T-29 | Double-wall Horizontal Open-top | 400 | 16,800 | Drilling fluids | 2014 | ADEC Approval #2014-01 | New; 2019 | New; 2019 | New 2014 | See letter dated 10/27/2014 in Section 3.11 |
| TANKO Alaska | T-30 | Double-wall Horizontal Open-top | 400 | 16,800 | Drilling fluids | 2014 | ADEC Approval #2014-01 | New; 2019 | New; 2019 | New 2014 | See letter dated 10/27/2014 in Section 3.11 |
| TANKO Alaska | T-31 | Double-wall Horizontal Open-top | 400 | 16,800 | Drilling fluids | 2014 | ADEC Approval #2014-01 | New; 2019 | New; 2019 | New 2014 | See letter dated 10/27/2014 in Section 3.11 |
| TANKO Alaska | T-32 | Double-wall Horizontal Open-top | 400 | 16,800 | Drilling fluids | 2014 | ADEC Approval #2014-01 | New; 2019 | New; 2019 | New 2014 | See letter dated 10/27/2014 in Section 3.11 |
| TANKO Alaska | T-33 | Double-wall Horizontal Open-top | 400 | 16,800 | Drilling fluids | 2014 | ADEC Approval #2014-01 | New; 2019 | New; 2019 | New 2014 | See letter dated 10/27/2014 in Section 3.11 |

**Notes:**

1. Listed tanks are not owned by COPA, but may be directly rented or leased by COPA. Owners are responsible for conducting appropriate inspections and for maintaining records according to the provisions of 18 AAC 75.066. Tanks leased (rented) directly by COPA are managed under COPA's Tank Management Program while under lease; tank records are subject to review by COPA. Prior to return to COPA facilities for use, tanks require current inspection, record review under COPA's Tank Management Program, and update of information in this table.

2. Tanks are required to be placed in secondary containment sized to 100% of the volume of the largest tank, plus additional volume for local precipitation, per 18 AAC 75.075(a). A compliance waiver must be in place for tanks that do not meet this requirement.

3. COPA is responsible for ensuring tanks meet regulatory requirements for leak detection systems, overfill protection, and testing of overfill protection per 18 AAC 75.066 as described in this ODPCP.

4. Tanks placed into service after December 30, 2008 must be constructed and installed in compliance with 18 AAC 75.066.

5. Tanks placed into service before December 30, 2008 do not require ADEC approval of construction standard. Prior to use, tank records are reviewed by COPA to determine the service history.

TABLE D-4

THIRD-PARTY OIL STORAGE TANKS 10,000 GALLONS OR GREATER NOT OWNED OR OPERATED BY COPA

| OWNER / OPERATOR | TAG NUMBER | TANK DESCRIPTION | VOLUME (BBL) | VOLUME (GAL) | CONTENTS | FABRICATION DATE | CONSTRUCTION STANDARD | EXTERNAL INSPECTION LAST; NEXT | INTERNAL INSPECTION LAST; NEXT | COMMENTS |
|---|---|---|---|---|---|---|---|---|---|---|
| Halliburton | 850 (S/N 100863) | Horizontal rectangular | 476 | 20,000 | Frac fluids | 2012 | ADEC Approval #2016-01 | 2017; 2022 | 2012; 2022 | rented from Lynden Oilfield Services, Section 3.11 |
| Halliburton | 851 (S/N 100864) | Horizontal rectangular | 476 | 20,000 | Frac fluids | 2012 | ADEC Approval #2016-01 | 2017; 2022 | 2012; 2022 | rented from Lynden Oilfield Services, Section 3.11 |
| Halliburton | 852 (S/N 100865) | Horizontal rectangular | 476 | 20,000 | Frac fluids | 2012 | ADEC Approval #2016-01 | 2017; 2022 | 2012; 2022 | rented from Lynden Oilfield Services, Section 3.11 |
| Halliburton | 853 (S/N 100866) | Horizontal rectangular | 476 | 20,000 | Frac fluids | 2012 | ADEC Approval #2016-01 | 2017; 2022 | 2012; 2022 | rented from Lynden Oilfield Services, Section 3.11 |
| Halliburton | 854 (S/N 100868) | Horizontal rectangular | 476 | 20,000 | Frac fluids | 2012 | ADEC Approval #2016-01 | 2017; 2022 | 2012; 2022 | rented from Lynden Oilfield Services, Section 3.11 |
| Halliburton | 855 (S/N 100869) | Horizontal rectangular | 476 | 20,000 | Frac fluids | 2012 | ADEC Approval #2016-01 | 2017; 2022 | 2012; 2022 | rented from Lynden Oilfield Services, Section 3.11 |
| Halliburton | 856 (S/N 100870) | Horizontal rectangular | 476 | 20,000 | Frac fluids | 2012 | ADEC Approval #2016-01 | 2017; 2022 | 2012; 2022 | rented from Lynden Oilfield Services, Section 3.11 |
| Halliburton | 857 (S/N 100872) | Horizontal rectangular | 476 | 20,000 | Frac fluids | 2012 | ADEC Approval #2016-01 | 2017; 2022 | 2012; 2022 | rented from Lynden Oilfield Services, Section 3.11 |
| Halliburton | 858 (S/N 100873) | Horizontal rectangular | 476 | 20,000 | Frac fluids | 2012 | ADEC Approval #2016-01 | 2017; 2022 | 2012; 2022 | rented from Lynden Oilfield Services, Section 3.11 |
| Halliburton | 859 (S/N 100874) | Horizontal rectangular | 476 | 20,000 | Frac fluids | 2012 | ADEC Approval #2016-01 | 2017; 2022 | 2012; 2022 | rented from Lynden Oilfield Services, Section 3.11 |
| Halliburton | 860 (S/N 100881) | Horizontal rectangular | 476 | 20,000 | Frac fluids | 2012 | ADEC Approval #2016-01 | 2017; 2022 | 2012; 2022 | rented from Lynden Oilfield Services, Section 3.11 |
| Halliburton | 861 (S/N 100894) | Horizontal rectangular | 476 | 20,000 | Frac fluids | 2012 | ADEC Approval #2016-01 | 2017; 2022 | 2012; 2022 | rented from Lynden Oilfield Services, Section 3.11 |
| Halliburton | 862 (S/N 100895) | Horizontal rectangular | 476 | 20,000 | Frac fluids | 2012 | ADEC Approval #2016-01 | 2017; 2022 | 2012; 2022 | rented from Lynden Oilfield Services, Section 3.11 |

## TABLE D-4
## THIRD-PARTY OIL STORAGE TANKS 10,000 GALLONS OR GREATER NOT OWNED OR OPERATED BY COPA

| OWNER / OPERATOR | TAG NUMBER | TANK DESCRIPTION | VOLUME (BBL) | VOLUME (GAL) | CONTENTS | FABRICATION DATE | CONSTRUCTION STANDARD | EXTERNAL INSPECTION LAST; NEXT | INTERNAL INSPECTION LAST; NEXT | COMMENTS |
|---|---|---|---|---|---|---|---|---|---|---|
| Halliburton | 863 (S/N 100896) | Horizontal rectangular | 476 | 20,000 | Frac fluids | 2012 | ADEC Approval #2016-01 | 2017; 2022 | 2012; 2022 | rented from Lynden Oilfield Services, Section 3.11 |
| Halliburton | 864 (S/N 100897) | Horizontal rectangular | 476 | 20,000 | Frac fluids | 2012 | ADEC Approval #2016-01 | 2017; 2022 | 2012; 2022 | rented from Lynden Oilfield Services, Section 3.11 |
| Halliburton | 865 (S/N 100898) | Horizontal rectangular | 476 | 20,000 | Frac fluids | 2012 | ADEC Approval #2016-01 | 2017; 2022 | 2012; 2022 | rented from Lynden Oilfield Services, Section 3.11 |
| Halliburton | 866 (S/N 100899) | Horizontal rectangular | 476 | 20,000 | Frac fluids | 2012 | ADEC Approval #2016-01 | 2017; 2022 | 2012; 2022 | rented from Lynden Oilfield Services, Section 3.11 |
| Halliburton | 867 (S/N 100802) | Horizontal rectangular | 476 | 20,000 | Frac fluids | 2012 | ADEC Approval #2016-01 | 2017; 2022 | 2012; 2022 | rented from Lynden Oilfield Services, Section 3.11 |
| Halliburton | 868 (S/N 100804) | Horizontal rectangular | 476 | 20,000 | Frac fluids | 2012 | ADEC Approval #2016-01 | 2017; 2022 | 2012; 2022 | rented from Lynden Oilfield Services, Section 3.11 |
| Halliburton | 869 (S/N 100805) | Horizontal rectangular | 476 | 20,000 | Frac fluids | 2012 | ADEC Approval #2016-01 | 2017; 2022 | 2012; 2022 | rented from Lynden Oilfield Services, Section 3.11 |
| Halliburton | T-14 | Tiger Tank | 500 | 21,000 | Oil; drilling fluids | In service pre-1992 | non-standard | 2014; 2019 | 2014; 2019 | rented from Lynden Oilfield Services |
| Halliburton | T-18 | Tiger Tank | 500 | 21,000 | Varies | 1990 | non-standard | 2014; 2019 | 2014; 2019 | rented from Lynden Oilfield Services |
| Halliburton | T-19 | Tiger Tank | 500 | 21,000 | Varies | 1990 | non-standard | 2015; 2020 | 2015; 2020 | rented from Lynden Oilfield Services |
| Halliburton | T-20 | Tiger Tank | 500 | 21,000 | Varies | 1990 | non-standard | 2014; 2019 | 2014; 2019 | rented from Lynden Oilfield Services |
| Halliburton | T-21 | Tiger Tank | 500 | 21,000 | Varies | 1990 | non-standard | 2014; 2019 | 2014; 2019 | rented from Lynden Oilfield Services |
| Ice Services | 128 Camp Tank | Dike Tank on Skid | 285 | 12,000 | Diesel | 2013 | UL-142 | New 2013; 2018 | New 2013; 2023 | Located at Kuukpik Pad |

TABLE D-4

THIRD-PARTY OIL STORAGE TANKS 10,000 GALLONS OR GREATER NOT OWNED OR OPERATED BY COPA

| OWNER / OPERATOR | TAG NUMBER | TANK DESCRIPTION | VOLUME (BBL) | VOLUME (GAL) | CONTENTS | FABRICATION DATE | CONSTRUCTION STANDARD | EXTERNAL INSPECTION LAST; NEXT | INTERNAL INSPECTION LAST; NEXT | COMMENTS |
|---|---|---|---|---|---|---|---|---|---|---|
| MI Swaco | E-02-034-S1 | Upright Tank (MI 32) | 600 | 25,200 | Drilling Fluids | 2002 | API 12 F | 2012; 2017 | 2012; 2022 | Located at Alpine CD1 Mud Plant |
| MI Swaco | E-02-034-S2 | Upright Tank (MI 34) | 600 | 25,200 | Drilling Fluids | 2002 | API 650 | 2016; 2021 | 2016; 2026 | Located at Alpine CD1 Mud Plant |
| MI Swaco | E-02-034-S3 | Upright Tank (MI 33) | 600 | 25,200 | Drilling Fluids | 2002 | API 650 | 2016; 2021 | 2016; 2026 | Located at Alpine CD1 Mud Plant |
| MI Swaco | E-98-272-2 | Upright Tank (MI 27) | 600 | 25,200 | Drilling Fluids | 1998 | API 12 F | 2013; 2018 | 2008; 2018 | Located at Alpine CD1 Mud Plant |
| MI Swaco | E-98-272-3 | Upright Tank (MI 28) | 600 | 25,200 | Drilling Fluids | 1998 | API 12 F | 2013; 2018 | 2008; 2018 | Located at Alpine CD1 Mud Plant |
| MI Swaco | E-98-272-4 | Upright Tank (MI 26) | 600 | 25,200 | Drilling Fluids | 1998 | API 12 F | 2015; 2018 | 2015; 2025 | Located at Alpine CD1 Mud Plant |
| MI Swaco | E-98-272-5 | Upright Tank (MI 30) | 600 | 25,200 | Drilling Fluids | 1998 | API 12 F | 2013; 2018 | 2008; 2018 | Located at Alpine CD1 Mud Plant |
| MI Swaco | E-98-272-6 | Upright Tank (MI 31) | 600 | 25,200 | Drilling Fluids | 1998 | API 12 F | 2013; 2018 | 2008; 2018 | Located at Alpine CD1 Mud Plant |
| MI Swaco | MI-A6061610 | ALP INJ SKID T-0001 | 1,000 | 42,000 | Drilling Fluids | 2013 (first service in 2014) | API 650 Appendix J | 2014; 2019 | 2014; 2024 | Located at Alpine Injection skid at CD1 |
| MI Swaco | MI-A6061611 | ALP INJ SKID T-0002 | 1,000 | 42,000 | Drilling Fluids | 2013 (first service in 2014) | API 650 Appendix J | 2014; 2019 | 2014; 2024 | Located at Alpine Injection skid at CD1 |
| MI Swaco | MI-A6061612 | ALP INJ SKID T-0003 | 1,000 | 42,000 | Drilling Fluids | 2013 (first service in 2014) | API 650 Appendix J | 2014; 2019 | 2014; 2024 | Located at Alpine Injection skid at CD1 |
| MI Swaco | MI-A6061613 | ALP INJ SKID T-0004 | 1,000 | 42,000 | Drilling Fluids | 2013 (first service in 2014) | API 650 Appendix J | 2014; 2019 | 2014; 2024 | Located at Alpine Injection skid at CD1 |
| Schlumberger | 2SUS15818 | Tiger Tank | 500 | 21,000 | Varies | 2000 | ADEC Waiver | 2013; 2018 | 2013; 2023 | ADEC approval Section 3.11 |

## TABLE D-4
## THIRD-PARTY OIL STORAGE TANKS 10,000 GALLONS OR GREATER NOT OWNED OR OPERATED BY COPA

| OWNER / OPERATOR | TAG NUMBER | TANK DESCRIPTION | VOLUME (BBL) | VOLUME (GAL) | CONTENTS | FABRICATION DATE | CONSTRUCTION STANDARD | EXTERNAL INSPECTION LAST; NEXT | INTERNAL INSPECTION LAST; NEXT | COMMENTS |
|---|---|---|---|---|---|---|---|---|---|---|
| Schlumberger | 2SUS16104 | Tiger Tank | 500 | 21,000 | Varies | 2000 | ADEC Waiver | 2013; 2018 | 2013; 2023 | ADEC approval - Section 3.11 |
| Schlumberger | 2SUS18473 | Horizontal rectangular | 500 | 21,000 | Varies | 2001 | ADEC Waiver | 2013; 2018 | 2013; 2023 | ADEC approval Section 3.11 |
| Schlumberger | 2SUS18603 | Tiger Tank | 500 | 21,000 | Varies | 2001 | ADEC Waiver | 2013; 2018 | 2013; 2018 | ADEC approval Section 3.11 |
| Schlumberger | 2SUS18606 | Tiger Tank | 500 | 21,000 | Varies | 2001 | ADEC Waiver | 2013; 2018 | 2013; 2023 | ADEC approval Section 3.11 |
| Schlumberger | 2SUS18607 | Tiger Tank | 500 | 21,000 | Varies | 2001 | ADEC Waiver | 2013; 2018 | 2013; 2023 | ADEC approval Section 3.11 |
| Schlumberger | 2SFF41961 | Horizontal rectangular Frac Tank | 500 | 21,000 | Varies | 2013 | ADEC Approval #2013-01 | New 2013; 2018 | New 2013; 2023 | See letter dated 2/28/2013 in Section 3.11 |
| Schlumberger | 2SFF41962 | Horizontal rectangular Frac Tank | 500 | 21,000 | Varies | 2013 | ADEC Approval #2013-01 | New 2013; 2018 | New 2013; 2023 | See letter dated 2/28/2013 in Section 3.11 |
| Schlumberger | 2SFF41963 | Horizontal rectangular Frac Tank | 500 | 21,000 | Varies | 2013 | ADEC Approval #2013-01 | New 2013; 2018 | New 2013; 2023 | See letter dated 2/28/2013 in Section 3.11 |
| Schlumberger | 2SFF41964 | Horizontal rectangular Frac Tank | 500 | 21,000 | Varies | 2013 | ADEC Approval #2013-01 | New 2013; 2018 | New 2013; 2023 | See letter dated 2/28/2013 in Section 3.11 |
| Schlumberger | 2SSF48256 | Horizontal rectangular | 500 | 21,000 | Varies | 2014 | ADEC Approval #2013-01 | New 2014; 2019 | New 2014; 2024 | See letter dated 2/28/2013 in Section 3.11 |
| Schlumberger | 2SSF48257 | Horizontal rectangular | 500 | 21,000 | Varies | 2014 | ADEC Approval #2013-01 | New 2014; 2019 | New 2014; 2024 | See letter dated 2/28/2013 in Section 3.11 |
| Schlumberger | 2SSF48258 | Horizontal rectangular | 500 | 21,000 | Varies | 2014 | ADEC Approval #2013-01 | New 2014; 2019 | New 2014; 2024 | See letter dated 2/28/2013 in Section 3.11 |
| Schlumberger | 2SSF48259 | Horizontal rectangular | 500 | 21,000 | Varies | 2014 | ADEC Approval #2013-01 | New 2014; 2019 | New 2014; 2024 | See letter dated 2/28/2013 in Section 3.11 |

## TABLE D-4
## THIRD-PARTY OIL STORAGE TANKS 10,000 GALLONS OR GREATER NOT OWNED OR OPERATED BY COPA

| OWNER / OPERATOR | TAG NUMBER | TANK DESCRIPTION | VOLUME (BBL) | VOLUME (GAL) | CONTENTS | FABRICATION DATE | CONSTRUCTION STANDARD | EXTERNAL INSPECTION LAST; NEXT | INTERNAL INSPECTION LAST; NEXT | COMMENTS |
|---|---|---|---|---|---|---|---|---|---|---|
| Schlumberger | 2SSF48260 | Horizontal rectangular | 500 | 21,000 | Varies | 2014 | ADEC Approval #2013-01 | New 2014; 2019 | New 2014; 2024 | See letter dated 2/28/2013 in Section 3.11 |
| Schlumberger | 2SSF48261 | Horizontal rectangular | 500 | 21,000 | Varies | 2014 | ADEC Approval #2013-01 | New 2014; 2019 | New 2014; 2024 | See letter dated 2/28/2013 in Section 3.11 |
| Schlumberger | 2SSF48262 | Horizontal rectangular | 500 | 21,000 | Varies | 2014 | ADEC Approval #2013-01 | New 2014; 2019 | New 2014; 2024 | See letter dated 2/28/2013 in Section 3.11 |

Note: Prior to return to use at COPA facilities, tank requires current inspection, record review under COPA's tank management program, and update of information in this table. Listed tanks are not owned by COPA. Owners are responsible for conducting appropriate inspections and for maintaining records according to the provisions of 18 AAC 75.066.

# APPENDIX E

# ADEC APPROVAL LETTERS

BLANK PAGE

THE STATE of ALASKA

GOVERNOR BILL WALKER

**Department of Environmental Conservation**

DIVISION OF SPILL PREVENTION AND RESPONSE
Prevention, Preparedness and Response Program

555 Cordova St
Anchorage, AK 99501
Office: 907-269-3094
Fax: 907-269-7687
www.dec.alaska.gov

File No.: 305.35
(CIE)

January 21, 2016

Jeanie Shifflett
Emergency Planning Coordinator
ConocoPhillips Alaska, Inc.
P.O. Box 100360
Anchorage, AK 99510-0360

**Subject: ConocoPhillips Alaska, Inc. Oil Discharge Prevention and Contingency Plans for the Kuparuk River Unit (Plan No. 12-CP-4102), Alpine Development (Plan No. 12-CP-4140), and North Slope Exploration (Plan No. 12-CP-5096). Tank Design Approval #2016-01**

Dear Ms. Shifflett:

The Alaska Department of Environmental Conservation (department) has reviewed ConocoPhillips Alaska, Inc.'s (CPAI) December 8, 2015 request for tank design approval. CPAI requested that the department approve an alternate tank design for portable 500-barrel "Frac" tank to be used by CPAI at its North Slope facilities.

18 AAC 75.066(b)(1) requires that shop-fabricated oil storage tanks be built to specified standards; however, 18 AAC 75.066(b)(2) allows alternate tank design if the design is certified by a registered engineer and is approved by the department as equivalent to a design for a standard listed in 18 AAC 75.066(b)(1). Detailed information about the tank design was submitted in emails and in hard copy form. The tank design was reviewed by the department's engineering staff. The following documents were included in CIE's submittal and were reviewed and considered for design approval.

1. Tank drawings, certified by Professional Engineer
2. Modified API 653 Inspection Report – initial, for new tank
3. Manufacturing specifications quality control inspection documentation
4. Hydro Test Report
5. Welding Procedure and Specification
6. Welding Procedure Qualification Record
7. Example photo of tank with this design

When operated at CPAI facilities, tanks of this design will be managed in accordance with applicable regulations of 18 AAC 75 and as described in the facility's Oil Discharge Prevention

and Contingency Plan. CPAI tank management personnel review tank records to verify compliance and document company approval of tanks for service prior to first operation in the field. In addition, a structural engineer registered in Alaska verified the integrity of the tanks through stress analysis modeling and certified the results.

The department's review indicates that tanks built per the submitted design criteria should be fit for service for atmospheric, hydrocarbon service. Based on the tank drawings, the tank meets the construction and appurtenance requirements of 18 AAC 75.066. The department approves this design as equivalent to a design for a standard listed in 18 AAC 75.066(b)(1). This alternate construction standard approval, "Tank Design Approval #2016-01," remains valid for tanks built to the design specifications. In the future, as long as there is verification that a tank is being built per this design package, no further evaluation by the department is necessary.

Please be advised that this approval does not relieve you of the responsibility for securing other state, federal, or local approvals or permits, and that you are still required to comply with applicable requirements of 18 AAC 75, Article 1 and all other applicable laws.

If you have any questions, please contact Gary Evans at (907) 269-7536 or via email at gary.evans@alaska.gov.

Sincerely,

Tom DeRuyter
Northern Alaska Region Manager

Electronic cc:

Laurie Silfven, ADEC
Gary Evans, ADEC
Jessica Starsman, ADEC
Sam Saengsudham, ADEC
Roger Burleigh, ADEC

THE STATE
of ALASKA
GOVERNOR SEAN PARNELL

Department of Environmental Conservation

DIVISION OF SPILL PREVENTION & RESPONSE
INDUSTRY PREPAREDNESS PROGRAM
Exploration, Production and Refineries

555 Cordova Street
Anchorage, Alaska 99501
Main: 907.269.3094
Fax: 907.269.7687

October 27, 2014

File No.: 305.35
(CPAI-Alpine, KRU, NSX)

Jeanie Shifflett
Emergency Planning Coordinator
ConocoPhillips Alaska, Inc.
P.O. Box 100360
Anchorage, AK 99510-0360

Subject: **ConocoPhillips Alaska, Inc. Oil Discharge Prevention and Contingency Plans for the Kuparuk River Unit (Plan No. 12-CP-4102), Alpine Development (Plan No. 12-CP-4140), and North Slope Exploration (Plan No. 12-CP-5096). Tank Design Approval #2014-01**

Dear Ms. Shifflett:

The Alaska Department of Environmental Conservation (department) has reviewed ConocoPhillips Alaska, Inc.'s (CPAI) September 25, 2014 request for tank design approval. CPAI requested that the department approve an alternate tank design for portable 400-barrel, rectangular storage tanks owned by Tank-O Alaska, LLC for use by CPAI at its North Slope facilities.

18 AAC 75.066(b)(1) requires that shop-fabricated oil storage tanks be built to specified standards; however, 18 AAC 75.066(b)(2) allows alternate tank design if the design is certified by a registered engineer and is approved by the department as equivalent to a design for a standard listed in 18 AAC 75.066(b)(1). Detailed information about the tank design was submitted on a CD, along with inspections and reports for two example tanks. The tank design was engineered by PCI Manufacturing, LLC. A conceptual review was conducted by the Industry Preparedness Program's Pipeline and Tank Integrity Section on the following design information:

- Tank drawings
- Welding Procedure Specifications and Welder Qualifications
- Welding Inspection Reports and Hydrotest and Air Test Reports
- Materials Summary and Test Reports
- Structural Calculations
- Coating Inspection Reports
- Coating Data Sheets
- Inspector Qualifications

Review of the design submittal substantiates that department approval of the tank design as equivalent to a standard listed in 18 AAC 75.066(b)(2) is warranted. A summary of findings is outlined below:

- The 400-barrel steel, horizontal, rectangular, double-wall, open-top tank is reported to have been designed and constructed to American Petroleum Institute (API) 650, *Welded Steel Tanks for Oil Storage*, including modifications in Appendix J for shop-assembled storage tanks, which meets the requirements of 18 AAC 75.066(b).
- The tank meets 18 AAC 75.066(e) by having an interstitial monitoring system, a fixed overfill spill containment system at the fill and dispensing ports, and a system for freeing any contents from the interstitial space.
- Structural calculations were performed and stamped by a licensed Alaska Professional Engineer.
- The construction drawings were approved and stamped by a licensed Alaska Professional Engineer.

The department's review indicates that tanks built per the submitted design criteria should be fit for service for atmospheric, hydrocarbon service. Based on the tank drawings, the tank meets the construction and appurtenance requirements of 18 AAC 75.066. The department approves this design as equivalent to a design for a standard listed in 18 AAC 75.066(b)(1). This alternate construction standard approval, "Tank Design Approval #2014-01," remains valid for tanks built to the design specifications. In the future, as long as there is verification that a tank is being built per this design package, no further evaluation by the department is necessary.

Please be advised that this approval does not relieve you of the responsibility for securing other state, federal, or local approvals or permits, and that you are still required to comply with applicable requirements of 18 AAC 75, Article 1 and all other applicable laws.

If you have any questions, please contact Laurie Silfven at (907) 269-7540 or via email at laurie.silfven@alaska.gov, or myself at (907) 269-7680 or graham.wood@alaska.gov.

Sincerely,

Graham Wood
Section Manager

Electronic cc:

Laurie Silfven, ADEC
Ashley Adamczak, ADEC
Sam Saengsudham, ADEC
Roger Burleigh, ADEC
Beth Heim, ADEC
Gary Evans, ADEC
Mike Evans, ADEC

THE STATE
of ALASKA
GOVERNOR SEAN PARNELL

# Department of Environmental Conservation

DIVISION OF SPILL PREVENTION & RESPONSE
INDUSTRY PREPAREDNESS PROGRAM
Exploration, Production and Refineries

555 Cordova Street
Anchorage, Alaska 99501
Main: 907.269.3094
Fax: 907.269.7687

February 28, 2013

File No.: 305.35 (Rev. 1)
(CPAI-Alpine, KRU, NSX)

Jeanie Shifflett
Emergency Planning Coordinator
ConocoPhillips Alaska, Inc.
P.O. Box 100360
Anchorage, AK 99510-0360

Subject: **ConocoPhillips Alaska, Inc. Oil Discharge Prevention and Contingency Plans. Tank Design Approval #2013-01 - Schlumberger Portable Tanks for the Kuparuk River Unit (Plan No. 07-CP-4102), Alpine Development (Plan No. 12-CP-4140), and North Slope Exploration (Plan No. 12-CP-5096). Revision 1**

Dear Ms. Shifflett:

The Alaska Department of Environmental Conservation (department) has reviewed ConocoPhillips Alaska, Inc.'s (CPAI) request for tank design approval dated November 21, 2012. CPAI requested that the department approve an alternate tank design for portable 500-barrel, rectangular storage tanks for use by CPAI at its North Slope facilities.

18 AAC 75.066(b)(1) requires that shop-fabricated oil storage tanks be built to specified standards; however, 18 AAC 75.066(b)(2) allows alternative tank design if the design is certified by a registered engineer and is approved by the department as equivalent to a design for a standard listed in 18 AAC 75.066(b)(1). CPAI submitted a design/construction package for five portable storage tanks owned by Schlumberger Technology Corporation and constructed in 2012. The tank design was engineered and built by Greer Tank and Welding, Inc. A conceptual review was conducted by the Industry Preparedness Program's Pipeline and Tank Integrity Section on the submitted design/construction package which included the following documentation:

- Hydrotest Certificates
- Certificate of Acceptance – Certificate of Compliance
- Welding Procedure Specifications
- Welding Qualification Test Record
- Professional Engineer Stamped Drawings
- Professional Engineer Stamped Structural Calculations
- Tank As-Built Drawings

Review of the design/construction package substantiates that department approval of the tank design as equivalent to a standard listed in 18 AAC 75.066(b)(2) is warranted. A summary of findings is outlined below:

- Structural calculations were performed and stamped by a licensed Alaska Professional Engineer.
- The construction drawings were approved and stamped by a licensed Alaska Professional Engineer.
- As-built drawings confirm design intent.
- The design criteria notes state that tanks were constructed to follow the basic design provisions of American Petroleum Institute (API) 650, *Welded Steel Tanks for Oil Storage*, 11th Edition, including Addendums 1, 2, and 3, and specifically Appendix J, *Shop-Assembled Storage Tanks*, unless deviations were specified. The design criteria notes indicate that API 650 provided the most appropriate guidance, even though this rectangular tank design does not fit the large volume, vertical cylindrical tank configuration typical of API 650.
- Welding documentation appears adequate.
  - Welding procedure specifications are based on American Society of Mechanical Engineers (ASME) IX and American Welding Society (AWS) D1.1 and were signed and stamped by an AWS-certified company representative.
  - Welder and Welding Operator Qualification Test records are signed and stamped by an AWS-certified company representative.
  - 100 percent of welds were specified for visual inspection.
  - 100 percent of butt welds at the wall plate, floor plate, and roof plate were specified for Liquid Penetrant examination.
- Tank inspections in accordance with API 653 were conducted by an API-certified inspector.
- Records indicate the tanks passed hydrostatic testing per Underwriters' Laboratories (UL) 142.

The department's review indicates that tanks built per the submitted procedures should be fit for service for atmospheric, hydrocarbon service. The department approves this design as equivalent to a design for a standard listed in 18 AAC 75.066(b)(1). This alternate construction standard approval, "Tank Design Approval #2013-01," remains valid for tanks built to the design/construction package specifications as long as the tank design and construction specifications are not modified and the tanks are operated within the established design parameters. In the future, as long as there is verification that a tank is being built per this design package, no further evaluation by the department is necessary. We request that CPAI give us advance notice of intended use of tanks built to this design standard.

Please be advised that this approval does not relieve you of the responsibility for securing other state, federal, or local approvals or permits, and that you are still required to comply with applicable requirements of 18 AAC 75, Article 1 and all other applicable laws.

If you have any questions, please contact Laurie Silfven at (907) 269-7540 or via email at laurie.silfven@alaska.gov, or contact me at (907) 269-7680 or graham.wood@alaska.gov.

Sincerely,

Graham Wood
Section Manager

Electronic cc:

Laurie Silfven, ADEC
Ashley Adamczak, ADEC
Sam Saengsudham, ADEC
Roger Burleigh, ADEC
Keith Sanfacon, ADEC

[illegible]

# STATE OF ALASKA

FRANK H. MURKOWSKI, GOVERNOR

555 Cordova Street
Anchorage, AK 99501
PHONE: (907) 269-3094
FAX: (907) 269-7687
http://www.state.ak.us/dec

## DEPT. OF ENVIRONMENTAL CONSERVATION

**DIVISION OF SPILL PREVENTION AND RESPONSE**
**INDUSTRY PREPAREDNESS PROGRAM**
**Exploration Production & Refineries**

February 9, 2005

File No. 305.35 (CPA/Alpine)

Mr. Jason Charton/Ms. Shellie Colegrove
Alpine Operations
ConocoPhillips Alaska, Inc. HSE-ALP 14
P.O. Box 196860
Anchorage, AK 99519-6105

Subject: **ConocoPhillips Alaska, Inc. (CPAI) Alpine Development Oil Discharge Prevention and Contingency Plan (plan). ADEC Plan Number 014-CP-4140.**
**<u>Waiver of Oil Storage Tank Construction Standards</u>**

Dear Mr. Jason Charton/Ms. Shellie Colegrove:

The Department of Environmental Conservation (Department) has reviewed your request dated December 23, 2004 and follow-on information provided for approval of an alternate construction standard for portable, 500-barrel, steel rectangular tanks (also referred to as "Tiger Tanks") to be used in the Alpine Development. Your submittal consists of drawings and supporting documentation for ten tanks owned by Schlumberger and constructed by Greer Tank and Welding. Under 18 AAC 75.065 (h)(1), tanks constructed, installed, or placed into service after May 14, 1992 must be built to API 650, API 12, or another standard approved by the Department.

The tank records do not contain sufficient information for the Department to approve the current or future construction standard of these tanks; however, in accordance with 18 AAC 75.015, ADEC may waive a regulatory requirement if the owner or operator demonstrates that an equivalent level of protection will be achieved by using a technology or procedure other than that required by 18 AAC 75.005 – 18AAC 75.090.

These tanks have undergone hydrostatic testing with the average holding time of 2.5 hrs for 7 tanks and over 8 hrs for 3 tanks. The testing fill heights were 8'11" and 8'10". The average water temperature (during the test) was 78 F.

The tanks have been in service on the North Slope for five years, and have therefore endured the "test of time." It is our understanding that the tanks have typically been used for frac jobs performed with water; however, the tanks will contain diesel for frac jobs at Alpine. It is our opinion that diesel service will not compromise tank integrity, since diesel has a lower specific gravity than water (between 0.82 and 0.95, depending on the grade).

Based on our review of your submittal, the Department approves continued use of these tanks for the same service conditions based on the conditions described below.

- The ten tanks with the following numbers are covered under this waiver: 2SUS18471, 2SUS18472, 2SUS18473, 2SUS18474, 2SUS18475, 2SUS18476, 2SUS18477, 2SUS18478, 2SUS18479, and 2SUS18480.
- Fill height of the tanks must be limited to the hydrostatic test fill height.

- The fluid stored in the tanks must have a specific gravity equal to or less than 1.0.
- Hydrostatic testing records must be kept as part of the permanent record of the tanks.
- Since the hydrostatic tests were conducted in a controlled environment, other operational and physical factors must be considered when specifying the operational fill height. The fill height and other operational constraints need to be part of the operating procedures for the tanks.

Assumptions and calculation worksheets are attached. Future designs or construction of similar tanks are not part of this waiver and will need to be evaluated on an individual basis to ensure that operational conditions are identical to the subject tanks.

The Alpine plan must be revised at the next routine update or minor amendment to include this waiver approval letter.

**Future Alternate Tank Construction Standard Approvals:**

For a typical storage tank construction standard, it is customary to see the following information. Please note that the list might not be all inclusive, but it follows the framework of API Standard 650.

- Intended service that defines the operating and environmental parameters for the tanks
- Materials (selection)
- Design, such as plate thickness and stiffeners spacing
- Fabrication/Erection
- Inspection (joints)
- Welding procedure(s) and welder(s) qualification
- Testing
- Procedures to ensure that the specifications are being followed

Additionally, we strongly emphasize the importance of designs having an Alaska Professional Engineer's (PE) seal as it will ensure solid evidence of sound practices and, if applicable, compliance with Alaska Statute (AS) 08.48. Alternatively, we recommend that designs lacking a PE stamp receive certification by CPAI's engineer.

If you have any questions regarding the review process, please contact Laurie Silfven at (907) 269-7540, or me at (907) 269-7680.

Sincerely,

Lydia Miner

Lydia Miner
Section Manager

cc: Bill Hutmacher, ADEC
Laurie Silfven, ADEC
Sam Saengsudham, ADEC
Ed Meggert, ADEC, NART, Fairbanks
Stephen Geddes/Jeanie Shifflett, CPAI, Anchorage

The evaluation is based on the following assumptions.

| Assumptions | Supporting Documents |
|---|---|
| Design pressure: 3.85 psi. However, use 3.75 psi (fill height of 8.6 ft) for calculation because of the specified maximum wall height. | Undated and unsigned engineering calculations. |
| Design specific gravity: 1.02 | Engineering calculation submitted on scratch paper (undated and unsigned) listing 64 $\frac{lbf}{ft^3}$ water has typical specific weight of 62.3 $\frac{lbf}{ft^3}$ at 60 F. |
| The material used: ASTM 36 -97A | Oregon Steel Mills Report. |
| Thickness for wall and bottom plates: 0.25" | Oregon Steel Mills Report. |
| Structural configuration: Wall and bottom – flat plate with stiffeners. | Undated, unstamped, not detailed (not all dimensions included) tank drawings. |
| Maximum as-built wall stiffeners spacing: 17" | Engineering calculation submitted on scratch paper. Date and author unknown due to the quality of the copy. |
| No initial hydrostatic testing performed after construction. | Only Greer Tank Air Test Certificate submitted. |
| Maximum fill height: 104 inches (8.66 ft) | Rectangular Tank Wall Design spreadsheet with the value of wall height of 104 inches. |
| Design allowable (membrane) stress: 27000 psi | Submitted documentations -Rectangular Tank Wall Design spreadsheet. |
| Allowable (membrane) stress using in evaluation calculation: 36000 psi | Typical published property of ASTM A36. Refer to Table 4-1 of API Std 653, latest edition. |
| Floor (beam) stiffeners spacing: 34" | Drawings submitted on 1/13/05 |

Evaluation methodologies:

1) Appendices I.7.3.1, I.7.3.2, and I.7.3.3 of API Std 650, 2003 Edition.

2) AISI Steel Plate Engineering Data – Vol 2- 1992.

Welding procedures not reviewed because this is an in-service review.

## Wall

**API 650, App I method:**

$F_y := 27000 \cdot \frac{lbf}{in^2}$ $\qquad t_g := 0.25 \cdot in$ $\qquad P := 3.75 \cdot \frac{lbf}{in^2}$

$$b := \left(1.5 \cdot F_y \cdot \frac{t_g^2}{P}\right)^{0.5}$$

$b = 25.981\,in$

Appendix I, API Std 650 equation is generally more conservative than the steel plate engineering equations. $F_y$ is 75% of the listed SMYS of A36 (36 ksi).

**Steel Plate Engineering Method:**

$F_y := 36000 \cdot \frac{lbf}{in^2}$

$$b_{max} := \left(\frac{F_y \cdot .75 \cdot t_g^2}{B \cdot P}\right)^{0.5} \qquad B := 0.5$$

$b_{max} = 30\,in$

Steel plate engineering equation, with B the most conservative assumption of B=0.5. $F_y$ used is 100% of A36's listed SMYS.

Where B is the longer side of a rectangular plate, and b is the shorter side.

Pressure used for both cal's is the max hydrostatic at the bottom and applied equally for the entire wall. The pressure actually decreases going up the liquid column. Note that no corrosion allowance (CA) is factored in for the calculation. If use double SF's - 75% SMYS AND 70% SMYS for joint efficiency, $b_{max}$ is = 25.1 inches.

## Floor:

### API 650, App I method:

$$F_y := 27000 \cdot \frac{lbf}{in^2} \qquad t_g := 0.25 \cdot in \qquad P := 3.82 \cdot \frac{lbf}{in^2}$$

$$b := \left(1.5 \cdot F_y \cdot \frac{t_g^{\,2}}{P}\right)^{0.5}$$

Pressure (P) is from SG=1.0 (pressure of 3.75 $\frac{lbf}{in^2}$ and weight of steel (pressure of 0.0707 $\frac{lbf}{in^2}$.

$$b = 25.742\,in$$

Appendix I, API Std 650 is generally more conservative (because it's a construction code) than the steel plate engineering equations. $F_y$ of 27000 psi is 75% of the listed SMYS of A36 (36 ksi). If use 36 ksi, maximum spacing is 29.72".

### Steel Plate Engineering Method (SPED):

$$F_y := 36000 \cdot \frac{lbf}{in^2}$$

$$b_{max} := \left(\frac{F_y \cdot .75 \cdot t_g^{\,2}}{B \cdot P}\right)^{0.5} \qquad B := 0.499$$

The coefficient $B_1$=0.499 is from Table 1-1B at ratio of B/b= (26*12)/34 = 9.18.

$$b_{max} = 29.754\,in$$

# STATE OF ALASKA

**DEPT. OF ENVIRONMENTAL CONSERVATION**
**DIVISION OF SPILL PREVENTION AND RESPONSE**
**INDUSTRY PREPAREDNESS PROGRAM**
**Exploration Production & Refineries**

*FRANK H. MURKOWSKI, GOVERNOR*

555 Cordova Street
Anchorage, AK 99501
PHONE: (907) 269-3094
FAX: (907) 269-7687
http://www.state.ak.us/dec


February 26, 2003

Mr. John Whitehead
Alpine Development Project
ConocoPhillips Alaska, Inc.
P. O. Box 196105
Anchorage, AK 99519-6105

File No: 305.30.4140

Dear Mr. Whitehead:

SUBJECT: **Approval (waiver) of Oil Storage Tank Construction Standards; Oil Discharge Prevention and Contingency Plan ("plan") for ConocoPhillips Alaska, Inc. (CPA) Alpine Development Participating Area; ADEC Plan number: 994-CP-4140**

The Department of Environmental Conservation (Department) has reviewed your January 27, 2003, request for approval for the construction of two types of tanks used for well-work, "Open Top" and "Tiger Tanks" as "another standard approved by the department" in accordance with 18 AAC 75.065(h)(1). The Department may waive a storage tank requirement of 18 AAC 75.065 if the owner or operator demonstrates that an equivalent level of protection will be achieved by using a technology or procedure other than that required [18 AAC 75.015(c )]. CPA has indicated, and the Department has confirmed, that there are no nationally recognized construction standards for the "Open Top" and "Tiger Tanks." Recognizing that there is no construction standard for these tanks to meet the "new installation" tank requirements of 18 AAC 75.065(h)(1), CPA developed a 'standard' for the construction of these tanks. CPA's standard includes welding procedure specifications, structural integrity calculations, material specifications, and other engineering design considerations to standardize the design, construction and fitness for service of these tanks, based on the intended uses and capacities of the subject tanks.

The specifications have been reviewed by the Department's engineer, Sam Saengsudham, and API 653 Certified Tank Inspector, Kirsten Ballard. Based upon this review, the Department has no objections to or additional comment on the use or design of the tanks as depicted in the BBFM Engineers Inc. design drawings and calculations, submitted on January 31, 2003, with the revised calculations and drawings for the Tiger Tank submitted on February 11, 2003. Based on the information supplied by CPA and discussions with CPA personnel, the Department is granting the waiver. CPA must include a copy of this waiver in the section of the plan designated as "Compliance Schedule and Waivers," currently Section 2.7, for the duration of the service life of the subject tanks. Facility diagrams and other information required by 18 AAC 75.425(e)(1-3) must also be included.

This waiver, including any necessary changes to the plan, must be incorporated into the plan renewal application currently in process prior to final distribution of the plan, when approved. CPA must notify the Department when any of the tanks are taken out of service or when major repairs are made [Ref: 18 AAC 75.065(e) and 18 AAC 75.415(a)]. This waiver is subject to the following conditions:

1) CPA must use the "Open Top" and "Tiger Tank" designs for any new tanks of these types at CPA's North Slope facilities. Any CPA facility that uses these tanks must include a copy of this waiver in the appropriate section of the applicable plan for the service life of the tanks included by this waiver. This waiver is transferable to CPA, its subsidiaries and purchasing agents, but not to other plan holders without prior approval.

*This condition is reasonably necessary to affirm that these tanks, and any other tanks of this type that are brought into service after May 14, 1992, meet the intent of 18 AAC 75.065(h)(1). The waiver is not transferable without prior approval, as required by 18 AAC 75.400 and 18 AAC 75.415(a).*

2) CPA will include the procurement procedures described below whenever new tanks of this type are ordered to ensure new oil storage tanks regulated under 18 AAC 75 are built to the appropriate code. This includes the modification of the "CPA Engineering Standards" for tank design, construction and placement into service to clearly define and identify the new oil storage tank construction requirements of 18 AAC 75.065 for CPA procurement processes. The changes to the CPA Engineering Standards and acceptance protocols will be communicated to CPA Operations/Drilling/Wells management and will be followed when CPA procures new oil storage tanks.

a) The proposed tank design will be developed in compliance with CPA's Tank Design Criteria and Welded Tank Procurement Specification or Fiberglass Reinforced Tank Specification, depending on whether the tank is of welded or fiberglass construction;

b) If a tank design code is desired that is not explicitly allowed by 18 AAC 75.065, a request for a waiver will be submitted to the Department for approval prior to the commencement of any construction work;

c) The new tank cannot be released for service until the Corrosion Department has completed a "Pre-Operational Tank Inspection Checklist" and all outstanding items have been resolved. This will ensure that the new tank has all the appropriate documentation and complies with 18 AAC 75.065 before it is put into service;

d) A record for the tank will be created in the Corrosion Department's "Tank Database," where future external and internal inspection dates will be assigned and entered. In addition, all records of inspection results and corrective actions will be kept for the service life of a tank, as required by 18 AAC 75.065(d);

e) The new tank information will be added to the applicable plan, currently Table 2-6;

f) The requirements of 18 AAC 75, as well as the above CPA procedural requirements, have been communicated to, and will continue to be followed by, the Wells, Drilling, Operations, Projects, Engineering and Procurement Organizations, or their equivalents should CPA reorganize, sell or otherwise re-name the organizations that make up CPA.

g) This waiver shall be binding to CPA, its agents, successors, and assigns and upon all persons, contractors and consultants acting on behalf of CPA.

*This condition is reasonably necessary considering that CPA is a large company with numerous employees, contractors, subcontractors, agents and potential successors, who may purchase oil storage tanks for use in the State of Alaska at the Kuparuk or Alpine facilities. Incorporating the requirements for new oil storage tanks into CPA's internal procurement process, including provisions for the sale of the company or its assets, is the best way to ensure that a new Tiger or Open Top tank that is ordered or placed into service after May 14, 1992, will meet the requirements of 18 AAC 75.065(h and j), that the information regarding a tank is maintained to meet the requirements of 18 AAC 75.065(d), and the information is maintained in the plan as required by 18 AAC 75.425(e)(2)(A).*

3) These tanks are subject to all other applicable requirements of 18 AAC 75.065 and 18 AAC 75.075 for tank inspection, maintenance, and secondary containment requirements.

*As required by 18 AAC 75.065(h)(1), this condition is reasonably necessary to insure that any new oil storage tanks needed for operations at CPA facilities on the North Slope will be submitted for approval prior to purchase, including "Open Top Tanks" and "Tiger Tanks" without the need for additional approvals for these two tank designs.*

Please be advised that the approval of this waiver does not relieve you of the responsibility for securing other state, federal or local approvals or permits, and that you are still required to comply with all other applicable laws.

If you have any questions, please contact Kirsten Ballard at 269-7541.

Sincerely,

Lydia Miner

Lydia Miner
Section Manager

cc: Kirsten Ballard, ADEC
Sam Saengsudham, ADEC
Sam Means, ADNR
Al Ott, ADFG
S. Adams, North Slope Borough
Brad Frates, CPA
Randy Kanady/Shellie Colegrove, CPA
Bob Hale/Steve Geddes, CPA
Michael Erwin, Supervisor, WNS Operations, CPA
Joseph A. Leone, CPA
Richard P. Mott, CPA
Tom Wellman, CPA

Mr. John Whitehead
ConocoPhillips Alaska, Inc.

f) The requirements of 18 AAC
have been
Operations,
should CPA

g) This waiver shall be binding to CPA, its agents, successors, and assigns and upon its
persons, contractors and consultants acting on behalf of CPA.

*This condition*
*employees, contractors,*
*storage tanks for use in the State of Alaska*
*the requirements for new oil storage tanks*
*provisions for the*
*Upon Top tank*
*requirements of 18 AAC*
*meet the requirements of 18 AAC*
*required by 18 AAC 75.472(c)(2)(A).*

3) These tanks are subject to
AAC 75.075 for tank inspection

*As required by 18 AAC 75.065*
*new oil storage tanks*
*submitted for approval*
*without the need for additional*

Please be advised that
securing other state, federal or local
comply with all other applicable

If you have any questions, please contact

cc: Kirsten Ballard, ADEC
Sam Saengsudham, ADEC
Sam Means, ADNR
Al Ott, ADFG
S. Adams, North Slope Borough
Brad Heuer, CPA
Randy Eaundy/Sheila Cotegrove, CPA
Bob Hale/Steve Gerlder, CPA
Michael Erwin, Supervisor, WNS Operations, CPA
Joseph A. Lacasse, CPA
Richard P. Mott, CPA
Tom Wellman, CPA

# STATE OF ALASKA

**DEPT. OF ENVIRONMENTAL CONSERVATION**
**DIVISION OF SPILL PREVENTION AND RESPONSE**
**INDUSTRY PREPAREDNESS PROGRAM**
**Exploration Production & Refineries**

*FRANK H. MURKOWSKI, GOVERNOR*
555 Cordova Street
Anchorage, AK 99501
PHONE: (907) 269-3094
FAX: (907) 269-7687
http://www.state.ak.us/dec

February 14, 2003

File No.: 305.40

Mr. John Whitehead
Alpine Development Project
Phillips Alaska, Inc.
P. O. Box 196105
Anchorage, AK 99519-6105

Dear Mr. Whitehead:

SUBJECT: **Waiver of Oil Storage Tank Construction Standards; Oil Discharge Prevention and Contingency Plan ("plan") for ConocoPhillips Alaska, Inc. (CPA) Alpine Development Participating Area. ADEC Plan number: 994-C4140.**

The Department of Environmental Conservation (Department) has reviewed your September 13, 2002, request for a waiver to operate several portable oil storage tanks and two fiberglass tanks (listed in Table 1) that do not meet the requirements of 18 AAC 75.065(h) for a "new installation." CPA recognized that these tanks did not meet the "new facility" tank requirements of 18 AAC 75.065(h)(1) and took immediate action to remove the tanks from service. While the initial request included approval of these tanks' construction as "another standard approved by the department" (Ref: 18 AAC 75.065(h)(1)), the tank records provided with the initial application did not contain sufficient information for the Department to approve the current or future construction 'standard' of these tanks as meeting the intent of 18 AAC 75.065(h)(1).

The Department has determined that the continued use of these tanks is permissible under the "test of time." These types of tanks have been in use for many years on the North Slope with no major problems noted due to their construction. No spills have been reported from these tanks since their use at Alpine, according to CPA's information. In addition, recognizing that a standard for these types of tanks needed to be developed, CPA agreed to develop such a standard as a condition of this waiver approval. The approval of those tank construction standards is addressed under separate correspondence.

Based on the information supplied by CPA and discussions with CPA personnel, the Department is granting the waiver. CPA must include a copy of this waiver in the section of the plan designated as "Compliance Schedule and Waivers," currently Section 2.7 of the plan, for the duration of the service life of the subject tanks. Facility diagrams and other information required by 18 AAC 75.425(e)(1-3), must also be included.

This waiver, including any necessary changes to the plan, must be incorporated into the plan renewal application currently in process prior to final distribution of the plan, when approved. CPA must notify the Department when any of the tanks are taken out of service or when major repairs are made. This waiver is subject to the following conditions:

1) CPA has developed an accelerated API 653 inspection schedule for the subject tanks, as outlined in Table 1 below to comply with 18 AAC 75.065(a). All API 653 inspections will be completed by May 2003. After the API 653 inspections are complete, CPA will have a qualified mechanical engineer, familiar with the design and construction of oil storage tanks, evaluate the tanks for continued service. The engineer evaluation will be completed by July 2003 and CPA will submit to the Department the results of this evaluation by August 2003, as well as the API 653 tank inspection results/reports for the subject tanks.

**Table 1**

| API 653 Alpine ADEC Tank Inspections for Waived Tanks | | | | | | |
|---|---|---|---|---|---|---|
| | | | Existing API 653 Inspection Schedule | | Accelerated API 653 Inspection Schedule | |
| Equipment Tag | Op. Unit | Tank Name | Last Internal | Last External | Next Internal | Next External |
| CF-T-76004 | ALP | OPEN TOP #4 | 5/12/2000 | 5/12/2000 | 5/2003 | 5/2003 |
| CF-T-76005 | ALP | OPEN TOP #2 | 5/12/2000 | 5/12/2000 | 5/2003 | 5/2003 |
| CF-T-76006 | ALP | 450 BBL TIGER TANK #6 | New 2000 | New 2000 | 5/2003 | 5/2003 |
| CF-T-76007 | ALP | 450 BBL TIGER TANK #5 | New 2000 | New 2000 | 5/2003 | 5/2003 |
| CF-T-76018 | ALP | 300 BBL GREEN OPENTOP | New 1998 | New 1998 | 5/2003 | 5/2003 |
| CF-T-76042 | ALP | HEATING FUEL TANK | 4/19/2001 | 4/19/2001 | 5/2003 | 5/2003 |
| CF-T-76043 | ALP | FUEL TANK | 5/3/2001 | 5/3/2001 | 5/2003 | 5/2003 |
| CF-T-76044 | ALP | JET FUEL TANK | 4/14/2001 | 4/14/2001 | 5/2003 | 5/2003 |
| CF-T-50063A | ALP | FIBERGLASS UPRIGHT | New 1998 | New 1998 | 5/2003 | 5/2003 |
| CF-T-50063B | ALP | FIBERGLASS UPRIGHT | New 1998 | New 1998 | 5/2003 | 5/2003 |

*This condition is reasonably necessary to affirm that these tanks, brought into service after May 14, 1992, are suitable for continued service. This inspection requirement will also ensure that the tanks meet all applicable requirements of an oil storage tank at an "existing installation," as required by 18 AAC 75.065(a, i, and j) and 18 AAC 75.990(39), since they cannot meet the requirements of 18 AAC 75.065(h), and it would cause undue hardship to require these tanks to be permanently taken out-of-service.*

2) CPA will review internal tank criteria and specifications to include revisions that ensure new oil storage tanks regulated under 18 AAC 75 are built to the appropriate code. This includes the modification of the "CPA Engineering Standards" for tank design, construction and placement into service to clearly define and identify the new oil storage tank construction requirements of 18 AAC 75.065 for CPA procurement processes. The changes to the CPA Engineering Standards and acceptance protocols will be communicated to CPA Operations/Drilling/Wells management to be included when CPA procures new oil storage tanks.

*This condition is reasonably necessary considering that CPA is a large company with numerous employees who may purchase oil storage tanks for use in the State of Alaska. Incorporating the requirements for new oil storage tanks into CPA's internal procurement process is the best way to ensure that any new oil storage tanks that CPA orders or places into service after May 14, 1992, will meet the requirements of 18 AAC 75.065(h and j).*

3) Future oil storage tanks that cannot be built to the 18 AAC 75 standards will be submitted to the Department for approval prior to design, purchase or placement into service. To facilitate this effort, CPA Engineering has worked with ADEC to develop standardized portable tank designs for "Open Top" and "Tiger Tank" styles for use in Alaska by CPA facilities on the North Slope. Regulatory approvals will be obtained prior to the start of construction of any other types of tanks for which there are no construction standards. Included in this effort is a new "Tank Acceptance Protocol," included in the project file, whereby the "CPA Corrosion Group" will verify that new oil storage tanks are in compliance with 18 AAC 75 prior to being placed in service. The parties have agreed that this will take the form of a tank pre-commissioning checklist, which will be included in the Department's approval of the alternative tank standards for the Open Top and Tiger tanks. In addition, the protocols, engineering standards and tank pre-commissioning checklist will be included in the Greater Kuparuk Area (GKA) Startup Status Checklist for the use of new storage tanks.

*As required by 18 AAC 75.065(h)(1), this condition is reasonably necessary to insure that any new oil storage tanks needed for operations at CPA facilities on the North Slope will be submitted for approval prior to purchase, and, to include approved tank designs for two types of oil storage tanks, known as the "Open Top Tank" and Tiger Tank for use without additional approval of these particular tank designs.*

Please be advised that the approval of this waiver does not relieve you of the responsibility for securing other state, federal or local approvals or permits, and that you are still required to comply with all other applicable laws.

If you have any questions, please contact Kirsten Ballard at (907) 269-7541.

Sincerely,

Lydia Miner

Lydia Miner
Section Manager

cc: Kirsten Ballard, ADEC
Sam Means, ADNR
Al Ott, ADFG
S. Adams, North Slope Borough
Brad Frates, CPA
Randy Kanady/Shellie Colegrove, CPA
Bob Hale/Steve Geddes, CPA
Michael Erwin, Supervisor, WNS Operations, CPA

# APPENDIX Q

# POTENTIAL MITIGATION MEASURES BEING CONSIDERED FOR ADOPTION IN GMT2 ROD

# APPENDIX Q: GMT2 PROPOSED MITIGATION MEASURES

The BLM held a 55 day public comment period after publication of the GMT2 Draft Supplemental EIS. BLM solicited comments from interested members of the public on potential new mitigation measures that could further avoid, minimize or compensate for the expected impacts of the GMT2 Project. BLM held 6 public meetings in Anaktuvuk Pass, Anchorage, Atqasuk, Fairbanks, Nuiqsut and Utqiagvik, and all potential new mitigation measures that met the guidelines for reasonableness outlined in the BLM's NEPA Handbook were included in the Final Supplemental EIS for possible inclusion in the Record of Decision (ROD). Mitigation measures proposed by BLM subject matter experts during production of the Draft or Final Supplemental EIS, as well as mitigation measures proposed by cooperating agencies and tribal entities during consultation were also included for consideration.

## Current BLM Mitigation Guidance

The mitigation measures adopted in the GMT2 ROD must meet the current guidance for mitigation outlined in the BLM NEPA Handbook, Instruction Memorandums and the NPR-A Regional Mitigation Strategy. Relevant text from the BLM NEPA Handbook is below:

> *Mitigation includes specific means, measures or practices that would reduce or eliminate effects of the proposed action or alternatives. Mitigation measures can be applied to reduce or eliminate adverse effects to biological, physical, or socioeconomic resources... and may be used to reduce or avoid adverse impacts, whether or not they are significant in nature. Measures or practices should only be termed mitigation measures if they have not been incorporated into the proposed action or alternatives. If mitigation measures are incorporated into the proposed action or alternatives, they are called design features, not mitigation measures. Monitoring is required to ensure the implementation of these measures (40 CFR 1505.2(c)) (see section 10.1, Purposes of and Requirements for Monitoring).*
>
> *In an EIS, all "relevant, reasonable mitigation measures that could improve the project are to be identified," even if they are outside the jurisdiction of the agency (see Question 19b, CEQ, Forty Most Asked Questions Concerning CEQ's NEPA Regulations, March 23, 1981).*

In addition to the BLM NEPA Handbook, the BLM has recently issued guidance on compensatory mitigation in BLM Instruction Memorandum 2018-093, Compensatory Mitigation, published July 24, 2018. Several mitigation measures were proposed by members of the public that meet the definition of compensatory mitigation. Instruction Memorandum 2018-093 precludes the adoption of these mitigation measures in the GMT2 ROD; however, BLM has included them in the Final Supplemental EiS to acknowledge stakeholder comments and to encourage consideration of these mitigation measures through other programs such as the State of Alaska's NPR-A Impact Mitigation Fund.

## Northeast NPR-A Regional Mitigation Strategy

The ROD for the GMT1 Project directed the BLM to prepare a Regional Mitigation Strategy (RMS) that would "serve as a roadmap for mitigating impacts from GMT1 and future projects enabled or assisted by the existence of GMT1." The RMS will help the BLM manage the NPR-A in a manner consistent with public law, and to fulfill the requirements of the National Environmental Policy Act (NEPA). The overall goal of the NPR-A RMS is to facilitate the expeditious development of oil and gas resources, while mitigating reasonably foreseeable and significantly adverse effects on the surface resources of the NPR-A. The RMS describes current and potential future mitigation actions or opportunities that should be considered when approving an application for development. The GMT2 ROD will identify mitigation measures that incorporate recommendations made in the RMS.

# Potential Mitigation Measures Being Considered for Adoption in the GMT2 Record of Decision

Below is a list of all the potential new mitigation measures that were identified in the GMT2 Final Supplemental EIS.

## Proposed New Mitigation Measures for Soils and Permafrost

### Potential Mitigation Measure 1: Alaska Natural Resources Conservation Service Level II Soil Survey

**Objective:** Establish baseline conditions of soils within 1,000-meter radius of all planned gravel infrastructure. This may be accomplished within the first year after the start of construction.

**Requirement/Standard:** The permittee shall conduct a soil survey that meets the requirements of the Alaska Natural Resources Conservation Service Level II soil survey (including ecological site description). The soil survey will extend for a 1,000-meter radius from all planned gravel infrastructure and will be accomplished prior to construction activities.

**Potential Benefits and Residual/Unavoidable Impacts:** Establishing baseline conditions will allow the BLM to monitor changes to the soil profile and vegetation as a result of airborne soil movement resulting from industrial activity. Addition of loess material will affect albedo resulting in increased active layer depth. It may also affect the vegetative community composition over time. This data will help delineate changes based on development activities from general change from warming temperatures. The data will help improve future engineering, design and permitting decisions thus mitigating future impacts.

## Proposed Mitigation for Air Quality

Best management practices and best available control technology will be implemented by ConocoPhillips for GMT2 construction, drilling, and routine operations in order to reduce project-related emissions and therefore impacts on the GMT2 Project area. Below are a list of potential mitigation measures that are proven emission reduction strategies and technologies that will be evaluated by BLM for adoption in its Record of Decision.

### Potential Mitigation Measure 1 — Warm Building for vehicle storage

**Objective:** Reduce air quality impacts from idling vehicles

**Requirement/Standard:** Construct building with sufficient size and capacity to heat vehicles to reduce the amount of idling vehicles.

**Potential Benefits and Residual/Unavoidable Impacts:** Actions taken to minimize impacts to air quality will assist with minimizing impacts to overall human health by reducing the potential sources of exposure that local residents may experience. Could reduce emissions by reducing numbers of idling vehicles. Would add to the footprint of the development, potentially increasing construction emissions. May concentrate emissions from numerous vehicles in a single area that would otherwise be distributed by moving vehicles throughout the project area.

## Potential Mitigation Measure 2—Minimize methane waste

**Objective:** Reduce air emissions of methane and protect human health and the environment.

**Requirement/Standard:** Measurement and reporting of all natural gas waste from venting, flaring and leaks. A methane waste capture plan would be developed and submitted with the APD. Also, ConocoPhillips would implement a leak detection and repair (LDAR) program in order to conduct preventative maintenance. Using either a Method 21 instrument such as a photo ionization detector or flame ionization detector or an optical gas imaging instrument such as a FLIR camera, inspections shall be conducted on a regular schedule to identify leaks and the need for repairs. As an additional measure of preventative maintenance, there should also be regular auditory, visual, and olfactory inspections.

**Potential Benefits and Residual/Unavoidable Impacts:** These preventative maintenance procedures will reduce the potential for hydrocarbon emissions such as VOC, hazardous air pollutants, and $CH_4$. These measures might also prevent or lessen the impacts of a potentially significant major unintentional release of material. This measure would also improve worker safety through reduction of accidental releases. The proponent would incur financial and man-power costs due to purchase of capital assets and necessary on-going labor to conduct this program.

As of this writing, it is not known how BLM's 2016 Methane Waste Prevention Rule might impact this mitigation measure due to on-going litigation.

## Potential Mitigation Measure 3—Use of Alternative Fuels (new subparagraph to BMP A-10)

**Objective:** Prevent unnecessary or undue degradation of the lands and protect health and ensure effectiveness of previously required mitigation measures.

**Requirement/Standard:** To the extent practicable, all oil and gas operations (vehicles and equipment) must be powered by natural gas or electric power rather than diesel fuel. To the extent natural gas and electric power are not practicable, the permittee will use gasoline rather than diesel to the extent practicable. Any vehicles and equipment that require diesel fuel must use ULSD as defined by the Alaska Department of Conservation, Division of Air Quality. ConocoPhillips will provide an annual report beginning one year after the ROD date to BLM Arctic District Office and BLM Alaska State Office Air Program lead reporting their use of and feasibility of natural gas, electric and gasoline powered equipment.

**Potential Benefits and Residual/Unavoidable Impacts:** Natural gas has fewer impurities, is less chemically complex, and generally results in less pollution when combusted than diesel fuel. In most applications, using natural gas produces less $CO_2$, $SO_2$, and particulate matter, than diesel fuel, resulting in reduced health risks from fuel combustion in equipment associated with oil and gas operations.

Natural gas is an available fuel for stationary combustion sources on the North Slope; however, vehicle fueling with natural gas may not be currently feasible due to a lack of infrastructure and availability of appropriate vehicles. Where use of natural gas is not practicable, use of gasoline generally results in less pollution when combusted than diesel fuel. Use of natural gas-generated electric power to operate GMT1 sources, rather than diesel-fired electric power generation, is environmentally beneficial. Reporting requirements will allow BLM to evaluate the effectiveness of this mitigation measure.

### Potential Mitigation Measure 4—Implementation of Air Quality Monitoring Data Review (new subparagraph to BMP A-10)

**Objective:** Provide BLM oversight and technical review of air quality monitoring near the GMT2 project; address concerns in the local community regarding oversight of air quality.

**Requirement/Standard:** As part of the GMT1 ROD, permittee is required to provide funding for monitoring to identify and address concerns related to air quality in the Nuiqsut area. Reports from the monitoring station in Nuiqsut are required to be provided to BLM, the State, NSB, and the local community and tribal government pursuant to BMP A-10(h). The permittee is required to provide funding for BLM technical review of these documents, via an ongoing cost reimbursement agreement. BLM may elect to have a contractor or another agency perform the technical review. Permittee will begin providing quarterly monitoring reports beginning at the end of the first quarter of calendar year 2019. The format and exact content of the reports as well as the cost reimbursement agreement will be negotiated with permittee by January 30, 2019.

**Potential Benefits and Residual/Unavoidable Impacts:** Members of the public have expressed concern over air quality in the project vicinity. Providing for a technical BLM review of the monitoring results provides certainty for BLM and the community that air quality is being carefully considered and will help identify any potential project-related impacts that would cause exceedances of NAAQS, or fail to protect public health.

### Potential Mitigation Measure 5— Electrification

**Objective:** To the extent possible, power on-site combustion sources with electricity rather than fossil fuels.

**Requirement/Standard:** Under all GMT2 Alternatives, it is expected that grid power will be available for electric support at the GMT2 drill pad. The onsite pad generator is expected to be used for emergency purposes only when grid power is not available. Power lines will be installed between GMT2 and nearby power generation facilities and should be relied upon in place of fossil-fuel combustion equipment.

**Potential Benefits and Residual/Unavoidable Impacts:** Will reduce on-site emissions from combustion sources. There will be some combustion sources that cannot be electrified, so there will be some residual combustion source emissions. May increase emissions from the source generating electricity for the site.

### Potential Mitigation Measure 6—Require Near Real Time Monitoring to Prevent Excess Emissions of Regulated Air Pollutants

**Objective:** Protect human health and the environment.

**Requirement/Standard:** To get real-time and site-specific data, ConocoPhillips should implement a telemetry monitoring system to provide effective management of production exceptions, while reducing the number of vehicle trips and miles traveled. In addition to the current ConocoPhillips-operated Nuiqsut

Monitoring Station, other monitoring systems should include supervisory control and data acquisition to monitor for malfunctioning equipment and production exceptions.

**Potential Benefits and Residual/Unavoidable Impacts:** These types of continuous monitoring systems would reduce the need for regular site inspections, reducing onsite truck traffic, and would alert field personnel of emission exception events in real-time therefore reducing emissions to the atmosphere that otherwise would have gone unnoticed.

### Potential Mitigation Measure 7—Air Quality Monitoring

**Objective:** Increase air quality monitoring to better determine actual impacts from development

**Requirement/Standard:** Due to the concern over ambient air in the GMT2 Project area and near Nuiqsut, and in line with the NPR-A Final Record of Decision BMP A-10 (BLM 2013a) to reduce unnecessary and undue degradation of the land and protect health, additional air quality monitoring will be required at the GMT2 pad. Permittee will begin air quality monitoring beginning after pad and road construction but before additional development (assumed to begin in January 2020). Permittee will set up the monitoring station as a telemetry monitoring system and will provide annual reports to BLM on air quality monitoring results. Data and reports will be provided through the end of the drilling phase of the GMT2 Project. Permittee should consider using a mobile air quality monitoring system similar to the BLM Wyoming Air Resource Monitoring System.

**Potential Benefits and Residual/Unavoidable Impacts:** There is very little ambient air quality monitoring data currently on the North Slope and in the vicinity of recent development. A telemetry monitoring system will allow permittee to take actions to reduce emissions in the event of an emissions exception, as well as provide BLM land managers useful air quality data to evaluate air strategy effectiveness. A mobile station will allow the permittee to move the air quality monitoring system to new developments as they are permitted.

### Potential Mitigation Measure 8—Use of Tier 4 Engines

**Objective:** Reduce air quality impacts from diesel engines

**Requirement/Standard:** When possible, the use of Tier 4 diesel engines instead of Tier 2 or Tier 3 engines should be operated in the field for drill rigs, completion rigs, generators, and other diesel-fired engines. For the emission inventories for Alternative A, B, and C, Tier 2 standards were assumed for all diesel-fired engines except for the routine operations emergency generator which was noted by ConocoPhillips to be a Tier 4 unit.

**Potential Benefits and Residual/Unavoidable Impacts:** Tier 4 engines have lower emission standards for NOx and PM, therefore resulting in less impacts from those pollutants. Impacts to air quality related values (AQRVs; visibility and atmospheric deposition) at Federal Class II areas could also be reduced.

### Potential Mitigation Measure 9—Selective and non-selective catalytic reduction devices:

**Objective:** Reduce emissions from combustion sources

**Requirement/Standard:** For engines, heaters, and other combustion devices, selective and non-selective catalytic reduction devices should be used to reduce criteria and hazardous air pollutant emissions such as NOx, CO, VOC, and formaldehyde, when feasible. Some selective catalytic reduction

devices inject ammonia into the exhaust to reduce NOx emissions; however, these types of devices should be avoided to prevent ammonia emissions.

**Potential Benefits and Residual/Unavoidable Impacts:** A reduction in combustion source emissions would result, commensurate with the number of devices that can be used. Impacts to local air quality would decrease as well as impacts to air quality and AQRVs at Federal Class II areas.

### Potential Mitigation Measure 10—Flaring or closed-loop systems

**Objective:** Reduce greenhouse gas emissions

**Requirement/Standard:** $CH_4$, a greenhouse gas, is the primary constituent of natural gas. Instead of venting natural gas during hydraulic fracturing or pigging operations, flaring will reduce VOC, hazardous air pollutant, and $CH_4$ emissions.

**Potential Benefits and Residual/Unavoidable Impacts:** Combustion emissions from flaring, in result, increase pollutant levels of NOx, CO, and $CO_2$. Overall greenhouse gas impacts would go down since the global warming potential of $CH_4$ is 25 times greater than $CO_2$. The hydrocarbon destruction efficiency of most flares is upwards of 95 percent. Also, a closed-loop system with 100 percent capture by re-routing gas from hydraulic fracturing or pigging operations to a sales line or onsite process results in no additional emissions to the atmosphere.

### Potential Mitigation Measure 11—Use of no-bleed or low-bleed pneumatic devices

**Objective:** Reduce hydrocarbon emissions

**Requirement/Standard:** In place of high-bleed or intermittent-bleed pneumatic devices for pressure, temperature, or liquid level control, no-bleed and low-bleed pneumatic devices should be installed, if feasible.

**Potential Benefits and Residual/Unavoidable Impacts:** No-bleed and low-bleed pneumatic devices will reduce hydrocarbon emissions, such as those of VOC, hazardous air pollutant, and $CH_4$ pollutants. Low-bleed pneumatic devices are classified as those with a bleed rate less than 6 standard cubic feet per hour (scfh). No-bleed pneumatic devices are those that are mechanically driven or solar-powered instead of powered by natural gas.

## Proposed New Mitigation for Vegetation and Wetlands

### Potential Mitigation Measure 1-- Reclamation of Wetlands, Natural Soils and Vegetation

**Objective:** Ensure project infrastructure is dismantled when no longer in use to promote reclamation of wetlands, soils and vegetation.

**Requirement/Standard:** When wells and facilities have met their useful life and are to be abandoned, recommendations found in the reclamation plan will be applied whenever feasible. Any planned reclamation goals will be in consultation with the local community, tribal government, and interested stakeholders.

**Potential Benefits and Residual/Unavoidable Impacts:** Reclamation can begin after the following two conditions are met: 1) the operator determines that a portion of a developed site will no longer be used for oil and gas operations and 2) BLM determines that environmental conditions are favorable for the

replacement and reestablishment of natural soils and vegetation. Returning vegetation and wetlands to a more natural state after removing gravel roads and pads will contribute to the long-term rehabilitation of the region. The permittee will report to the BLM on the latest research and methods related to reclamation of oil and gas infrastructure and roads in the arctic every 2 years. Abandonment and reclamation activities within the NPR-A are governed by 43 CFR Part 3160, subpart 3162, which requires lessees to reclaim the land in accordance with plans approved by the BLM (43 CFR 3162.3-4 and 3162.5-1).

## Proposed New Mitigation Measure for Fish

### Potential Mitigation Measure 1—Ensure Compliance with BMP E-6

**Objective:** Ensure that water flowing out of Lake M9925 and moving toward Blackfish Creek is not impeded by the road and that upstream fish passage by ninespine stickleback is possible, in accordance with requirements laid out in BMP E-6.

**Requirement/Standard:** Two weeks before placing culverts, submit to BLM the technical drawings for this area that show the planned placement of culverts as well as the road line and culvert points overlain on high-resolution imagery in GIS.

**Potential Benefits and Residual/Unavoidable Impacts**: This additional measure will enable the BLM to further evaluate pre-construction plans in an effort to increase the likelihood that the objective of BMP E-6 is met.

## Proposed New Mitigation Measures for Birds

### Potential Mitigation Measure 1: Roadkill Monitoring System for Birds and Wildlife

**Objective:** Implement a reporting system to monitor roadkill of birds and other wildlife on transportation routes.

**Requirement/Standard:** The permittee shall provide an annual report to the Authorized Officer reporting roadkill of birds and mammals to help the BLM determine whether additional preventative measures on vehicle collisions should be made.

**Potential Benefits and Residual/Unavoidable Impacts:** Knowledge about bird and mammal mortality due to vehicle traffic will help managers to develop methods to reduce collision rates with vehicles.

### Potential Mitigation Measure 2: Directional Facility Lighting

**Objective:** To prevent episodic bird collisions with infrastructure, especially during migration and inclement weather.

**Requirement/Standard**: .

All facility external lighting, during all months of the year, shall be designed to direct artificial exterior lighting inward and downward or be fitted with shields to reduce reflectivity in clouds and fog conditions, unless otherwise required by the Federal Aviation Administration.

**Potential Benefits and Residual/Unavoidable Impacts:** *(see public comment)*

Best Management Practice E-10 contained in the 2013 NPR-A IAP ROD contains very similar language to this proposed mitigation measure with that exception that E-10 is in effect between August 1 and October 31 only. In their comments the USFWS pointed out that "Lighted facilities (drill rigs and buildings) can cause episodic bird collisions with infrastructure, especially during migration and inclement weather" which is why this new mitigation measure removes the timing limitations and extends the BMP to being applicable year round. The benefit for including this new mitigation measure is to mitigate the collision risk to birds year round.

### Potential Mitigation Measure 3: Gravel Pit Rehabilitation

**Objective:** To prevent subsidence within gravel excavation pits and improve site rehabilitation for the benefit of nesting waterfowl.

**Requirement/Standard**: A 3:1 side slope and perimeter berm during excavation on the ASRC pit. Once the pit fills with water, the perimeter berm shall be pushed into the pit.

**Potential Benefits and Residual/Unavoidable Impacts:** (see public comment)

The DSEIS indicates the new cells mined for the GMT2 development will be rehabilitated as a matrix of undisturbed tundra, deep water, shallow, and very shallow littoral, and waterfowl nesting islands. The previous rehabilitation efforts of Phase 1, mined in the late 1990s and early 2000s, to create similar habitats as described above have failed. The latest photo (2017) shows an approximately 95% reduction in the overburden islands and continued subsidence of the channel cut islands and complete subsidence of the littoral shelf to the north. In order to avoid repeating previous failures Phase 3 of the ASRC pit be mined without the intention of creating shallow habitats. Best Management Practices (BMPs) should be used during excavation (3:1 side slopes and a perimeter berm to prevent thermokarsting and for safety.) Once the pit fills with water the perimeter berm can be pushed into the pit creating the desired matrix of habitats.

## Proposed New Mitigation Measures for Mammals

### Potential Mitigation Measure 1: Roadkill Monitoring System for Birds and Wildlife

**Objective:** Implement a reporting system to monitor roadkill of birds and other wildlife on transportation routes.

**Requirement/Standard:** The permittee shall provide an annual report to the Authorized Officer reporting roadkill of birds and mammals to help the BLM determine whether additional preventative measures on vehicle collisions should be made.

**Potential Benefits and Residual/Unavoidable Impacts:** Knowledge about bird and mammal mortality due to vehicle traffic will help managers to develop methods to reduce collision rates with vehicles.

### Potential Mitigation Measure 2: (Adapted from BMP K-5.e.1 and 2): Minimize Potential Ground Vehicle Traffic Disturbance of Caribou

**Objective:** Minimize disturbance and hindrance of caribou, or alteration of caribou movements, by vehicle traffic on the GMT1-GMT2 gravel road during the oestrid fly-relief and fall-migration seasons.

**Requirement/Standard:** The following ground vehicle traffic restrictions shall apply to permitted activities using the GMT1-GMT2 road in the time periods indicated:

1. Along the GMT1-GMT2 road, from July 16 through November 30, traffic speed shall not exceed 15 miles per hour when caribou are within 0.5 mile of the road. If caribou are observed regularly within 0.5 miles of the road (i.e. observed daily for 3 or more consecutive days) then additional strategies would be implemented including restricting vehicle traffic or requiring vehicles to travel in convoys.
2. The permittee or a contractor shall observe caribou movement from July 16 through November 30 to assess whether or not caribou may be trying to cross the road. Based on the assessment, traffic will be stopped temporarily if it is determined that caribou are trying to cross the road. Any individual or group of caribou moving steadily toward the road within a distance of 0.25 miles (approximately 400 meters) should be considered attempting to cross the road. Sections of road will be closed to vehicle traffic whenever an attempted crossing by 100 caribou or more appears to be imminent.
3. The permittee shall submit, prior to road construction, a vehicle use plan that considers these and any other appropriate mitigation measures. Adjustments will be required by the Authorized Officer if resulting disturbance is determined to be unacceptable.
4. The permittee will consult with the Authorized Officer annually to determine if the seasonal restrictions, and restrictions described in paragraphs 1 and 2 above are still appropriate given possible changes in migration patterns. In light of ongoing caribou monitoring, the Authorized Officer may modify the restrictions as appropriate to achieve the objectives of this measure.

**Potential Benefits and Residual/Unavoidable Impacts***:* Limiting vehicle traffic during caribou migration will help reduce impacts and disturbance to caribou. Unavoidable impacts would continue due to the presence of the road and continued traffic.

## Proposed New Mitigation Measures for Sociocultural Systems

Through the consultation process, local entities and residents have already suggested numerous potential benefits to the community that they believe could begin to offset the negative impacts to their way of life. Although the BLM lacks the authority to require implementation of these measures, many of which could be considered social services, they are presented here.

### Locally Requested Mitigation Measures

Through the consultation process, local entities and residents have suggested numerous potential benefits to the community that they believe could begin to offset the negative impacts to their way of life. Although the BLM lacks the authority to require implementation of these measures, many of which could be considered social services, they are presented here.

#### Heritage Center in Nuiqsut

When asked what could offset the sociocultural impacts Nuiqsut would experience with development of GMT1, several residents articulated the need for a local heritage center and a place for youth sports and activities. This mitigation measure would address the fact that the community of Nuiqsut's community center is no longer an ideal location for social events due to the regular development-related meetings that are held there, and would be a place where the community could meet, pass on traditional knowledge, and actively participate in cultural activities.

## Support Cultural and Educational Projects

Support projects that document, teach, and protect culture, history, and language, such as: establishing a library with a focus on Iñupiat culture that is open year-round; establishing a community-based photojournalism/media institute, build recreation centers, teen centers, playgrounds, and/or picnic areas.

## Provide Administrative and Technical Support

Assist communities in communicating with levels of government to get issues of concern addressed, such as hiring permanent grant writers to submit proposals for impacts mitigation and other grants and to produce grant requests, and assist local entities with obtaining technical and legal expertise to advise them on the permitting process.

## Nuiqsut Drug Rehabilitation Program

The 2005 Nuiqsut Village Profile, based on data compiled during a comprehensive survey of every North Slope Borough household, noted this issue as a community priority: "Social services – A rehabilitation program, with certified counselors, is needed in the community" (URS Corporation 2005). The lack of local counseling and drug rehabilitation programs is understood by some locals as preventing local employment in the oil field.

## Provide Educational Support

Assist with the implementation/expansion of Science Technology Engineering Math programs within local schools, such as the Alaska Native Science and Engineering Program in impacted communities. Support the development and implementation of job training programs in North Slope communities, including local oversight/monitoring of development activities (e.g., staff, training, funding to contract for technical and scientific expertise).

The NSB suggests that industry could fund a local science center that could be associated with one of the suggested buildings. The Borough reports great success despite minimal local resources conducting science within NSB communities, typically with the assistance and support of local hunters and the participation of local residents. With a dedicated facility containing basic equipment, industry could support occasional important scientific research in Nuiqsut with the support and participation of local residents.

## Provide Economic and Community Development Opportunities

Develop and implement programs that support local entrepreneurial and economic development in impacted communities. Fund the development of long-term community development plans for impacted communities. Build new housing to meet growing demand in impacted communities.

Residents have noted that many past workforce development efforts have been geared exclusively towards oil industry jobs, while the majority of the jobs available on the North Slope are no longer for industry (or that industry jobs are not feasible for parents or caregivers who must stay in town). The concern is that everyone who is qualified for a job in industry is quickly hired and relocated to Anchorage. The suggestion is that workforce development efforts should refocus to support preparation for those jobs that are available in the communities, primarily teachers and nurses.

## Establish a BLM Field Office in Nuiqsut

Local residents have not only requested that an office be established by the BLM in the community of Nuiqsut, but that it be staffed by a local who is charged with inspection and enforcement authority on behalf of the federal government. By having an office in Nuiqsut, local residents would be able to more

easily receive timely information and answers to questions, and report issues, local concerns and violations to stipulations or best management practices.

### Postpone Approval of Development Projects until Impacts are Understood

Several local residents and entities expressed frustration regarding the hypothetical nature of how potential impacts are described within the Draft EIS. They have requested the USDOI and BLM postpone approving the GMT2 application, and future development applications, for a period of 5 years. The purpose of the postponement is to allow for local residents to experience the presence of GMT1, and for BLM and other entities to collect concrete data regarding resource displacement and other potential impacts, access enhancers and barriers, and other potential changes that will result from new the new development. This data could then contribute to a NEPA analysis that is based on data regarding the impacts and benefits that have occurred from a similarly designed and constructed development.

### Search and Rescue Assistance

Local residents of Nuiqsut have expressed concern regarding the ability of current Search and Rescue capabilities within the community given that local hunters are traveling farther away to harvest resources, leading to safety concerns both in terms of increased potential for local residents to need assistance, and increased capacity for Search and Rescue response. Specific Requests include:

- Upgrades for Search and Rescue Equipment
- Upgrades for Search and Rescue communications, radio and satellite
- Additional training for Search and Rescue Responders

### Potential Mitigation Measure #1: Nuiqsut Area Environmental Information Dissemination

**Objective:** Make data and summary reports derived from local studies available locally.

**Requirements/Standard:** The permittee will create a simple, user-friendly website where data, studies, reports, and research summaries associated with required monitoring studies are maintained and made accessible. These documents will be made accessible via the website within 2 months of finalization.

The website should not require the creation of accounts or passwords or restrictions on access of any kind. When new documents are added to the website, the permittee will notify residents and the BLM by email and by posts to any industry-maintained social media accounts (i.e., the Nuisagmiut Facebook group). The permittee will also print copies of summary reports and distribute them to Nuiqsut entities (including, but not restricted to, Trapper School, KSOP, Kuukpik, NVN, and City of Nuiqsut).

At a minimum, the website and notification system will include all data and reports related to required monitoring studies that pertain to the environment within 50 miles of Nuiqsut on BLM-managed land. The permittee is encouraged to make other (non-industry contracted) research on the same area accessible in the same manner.

**Potential Benefits and Residual/Unavoidable Impacts:** Much of the data that is used by federal agencies conducting NEPA analyses is either information derived from studies and research paid for by the applicant, or conducted by agencies (i.e., federal, state and local government entities). There is no systematic way that residents can review these studies. In addition, residents have stated that many of the reports that present the data or study results are too complicated, and not effective at communicating important information that they need to be able to assist with the NEPA process. This contributes to a pervasive belief among local residents that much of this data is compromised, in that the entities who paid

for or collected the information have a vested interest in manipulating the data in some way (i.e., downplaying, minimizing, or increasing results; sabotaging accurate data collection; or summarizing information in non-meaningful ways). These conflict of interest concerns could be mitigated, in part, by the new methodology and peer review requirements established by Potential Subsistence Mitigation Measure 8 (section 4.4.5.6) and this Nuiqsut Area Environmental Information Dissemination measure would mitigate confusion over which studies are being conducted and what the findings are.

Although not a part of the BLM requirement/standard, local entities have requested support to engage their own contractor who would be responsible for working with local entities and the school to disseminate information on the studies and to prepare research summaries that effectively communicate research and data in a manner that is understood by residents.

## Proposed New Mitigation Measures for Subsistence

In addition to the lease stipulations and best management practices that apply to all oil and gas activities in the NPR-A established by the NPR-A Integrated Activity Plan/EIS (BLM 2013), an extensive set of subsistence mitigation measures for the GMT1 project was established with the 2015 GMT1 Record of Decision. Similar mitigation measures are proposed for GMT2 and additional potential mitigation measures have been developed through consultation with stakeholders or proposed via input on the Draft SEIS for GMT2.

### Potential Mitigation Measure 1: GMT2 Road Right of Access Agreement

**Objective:** Ensure that residents will have the right to use the GMT2 Access Road throughout the life of the project and ensure that residents are aware of the policies regarding use of project-associated roads for subsistence activities to reduce misunderstandings and ensure the safety of project workers and local residents using the roads.

**Requirement/Standard:** The permittee will produce a clear and legally binding right of access agreement that will provide the community of Nuiqsut with concise policies regarding use of the roads associated with the project and hunting prohibitions, if any, along the roads and near project components. Permittee will insure that this agreement is disseminated throughout the community. The permittee will also include a presentation on the agreement in its employee orientation, will ensure that sub-contractors have the agreement for their employee orientation, and will post the agreement on the road itself. The agreement should also be provided to BLM for their records.

**Potential Benefits and Residual/Unavoidable Impacts:** Clear policies regarding use of project roads for subsistence activities will likely reduce misunderstandings about whether and to what extent local harvesters can use and/or hunt from the road. Residents will be more likely to use project roads if they are well informed about company policies and security restrictions.

### Potential Mitigation Measure 2: Suspend Non-essential Helicopter Traffic during Peak Caribou Hunting Season

**Objective:** To reduce the impacts of helicopter traffic on Nuiqsut caribou hunters.

**Requirement/Standard:** Via ongoing consultation with the City of Nuiqsut, the North Slope Borough Department of Planning, Native Village of Nuiqsut, Kuukpik Corporation, and the Kuukpik Subsistence Oversight Panel, Inc., the BLM will establish an approximately 1-month-long period during peak caribou hunting when non-essential helicopter flights will be suspended within a predetermined distance of rivers that have been documented as caribou subsistence use areas, or limit helicopter traffic during this time to

established flyways. The consultation results should be documented, distributed to BLM and other stakeholders, and clearly identify actions to be implemented based on the consultation.

- Ongoing (multi-year, already planned) scientific/environmental studies that depend on access to study sites that are already planned could continue if there is no alternative access to sites.
- Suspension dates can be revised every 3 years upon review of peak caribou season.

**Potential Benefits and Residual/Unavoidable Impacts:** Reducing helicopter traffic or limiting the geographic area affected by helicopter traffic would reduce the incidence of conflicts between GMT2-related helicopter traffic and Nuiqsut subsistence activities. However, other operators on the North Slope may continue to fly during the suspension period.

## Potential Mitigation Measure 3: Consultation Regarding Aircraft Communication Protocols

**Objective:** Ensure that current communication protocols related to helicopter and fixed-wing air traffic by the permittee are adequate in addressing Nuiqsut concerns about the impacts of air traffic on their hunting activities.

**Requirement/Standard**: In consultation with local hunters and local organizations, the permittee will continue to facilitate, improve, and expand communication protocols to inform subsistence users of daily flight patterns and identify potential conflict areas during peak hunting times. This consultation should include efforts to advertise these communication protocols within the community so that Nuiqsut subsistence harvesters are aware of them and confirmation that existing minimum altitude requirements are adequate. The consultation results should be documented, distributed to BLM and other stakeholders, and clearly identify actions to be implemented based on the consultation.

**Potential Benefits and Residual/Unavoidable Impacts:** Strong communication protocols with the community of Nuiqsut regarding the timing, altitude, and location of air traffic should reduce the frequency of these impacts on subsistence users. However, such protocols will not remove impacts of air traffic altogether.

## Potential Mitigation Measure 4: Aircraft Monitoring Data Requirements

**Objective:** Monitor aircraft patterns and the impacts of aircraft associated with the GMT2 Project on subsistence hunting activities in the project area.

**Requirement/Standard:** Permittee will be responsible for funding and providing data to BLM for a monitoring study of aircraft flight patterns and impacts related to aircraft traffic on subsistence activities. The permittee will provide the BLM with data from the monitoring study in a manner that facilitates meaningful analysis of activities and impacts.

The permittee will provide BLM with clear and detailed quarterly flight reports that include the timing, flight path, and purpose of each flight in the project area.

The reports will highlight all flights that represent deviations from BLM's best management practices and include explanations for any deviations.

The permittee will provide data related to altitude of flights patterns. Noise data associated with altitudes will be cross-referenced to determine minimum altitudes for flights in the project area, to reduce impacts on wildlife and subsistence activities.

The aircraft monitoring plan will differentiate to the greatest degree practicable between the various purposes of flights (i.e., flights that are conducted for exploratory drilling operations, offshore pipeline baseline studies, and other scientific research broken down by species and researcher).

Reports will include statistical analyses on flight patterns, including how often actual flights and patterns deviate from the flight plan currently submitted to BLM under existing BMP F-1.

Monitoring undertaken to provide baseline data or to monitor effectiveness of mitigation measures must meet the approval of the authorized officer. As the authorized officer deems it appropriate, the data collection process and product shall be consistent with standards established by BLM's Assessment, Inventory, and Monitoring Program.

**Background, Potential Benefits, and Residual/Unavoidable Impacts:** Improved monitoring and analysis of flights, flight purposes, and other flight patterns will assist BLM to estimate the impacts of proposed actions or to formulate appropriate plans to reduce impacts. A monitoring study would provide a better understanding of how many aircraft are being used for different purposes, whether and how industry could reduce flights, and how aircraft and flight altitude affect subsistence activities and wildlife and in the project area. It is anticipated that such a monitoring plan will be significantly useful for the permittee and could direct the permittee to greater cost savings and efficiencies. It is anticipated that if aircraft traffic is not the reason for failed hunts, such a plan may be able to substantiate that. Data collected from this study will help BLM to adapt management decisions to changing conditions and circumstances and make better decisions for future research studies and development projects in the NPR-A.

## Potential Mitigation Measure 5: Reduce Flights by Utilizing Unmanned Aerial Vehicles

**Objective:** To reduce the impacts of aircraft traffic on Nuiqsut subsistence activities.

**Requirement/Standard:** The permittee will begin to employ unmanned aerial vehicles to conduct monitoring activities that otherwise require helicopters (i.e., pipeline inspections, studies, and other appropriate activities). The permittee will consult with the authorized agency every 3 years to determine feasibility of this technology and appropriate monitoring activities for its use.

**Background, Potential Benefits and Residual/Unavoidable Impacts:** Much of the ecological monitoring required of lessees and permittees is supported by/requested by local residents, but there is less understanding and little support for the number of helicopter flights that are required to conduct those activities. The potential for using unmanned aerial vehicles for baseline monitoring was discussed at the September 2013 NPR-A Subsistence Advisory Panel meeting when a representative of Shell Oil announced that that company was experimenting with using them. The Subsistence Advisory Panel was supportive of their use to decrease impacts from helicopters. Unmanned aerial vehicles have been utilized for oil field studies at Prudhoe Bay, and have the potential for use in the NPR-A. Residents of Nuiqsut have requested that the latest technology be used for such studies as soon as and to the greatest extent possible in order to alleviate the high number of aircraft flights. BLM would not have the authority to implement this best management practice on lands that are not managed by the BLM in the Nuiqsut area, where much of the disturbance from aircraft occurs.

## Potential Mitigation Measure 6: Subsistence Monitoring Studies

*Objective:* Monitor the impacts of GMT2 development on subsistence patterns, harvests, and associated subsistence activities for the community of Nuiqsut.

*Requirement/Standard:*

1). Initially (one time), the permittee will provide for an all-resources subsistence mapping study to document contemporary subsistence use patterns for Nuiqsut.

*Potential Benefits and Residual/Unavoidable Impacts:* The 2010 BOEM mapping study for all subsistence resources (SRB&A 2010a) has been valuable for this SEIS and several other North Slope analyses. The 2010 mapping study is based on data collected 1995-2006, thus the data is 12 years old and might not reflect changes that have occurred since 2006 or reliably confirm continuity. The one time initial mapping study will include all resources. The decadal interim will provide a comprehensive overview of any changes in subsistence use patterns during a period of development expansion near the community.

2) The permittee will monitor, through the life of the project, changes in subsistence activities in the community of Nuiqsut. The permittee will provide for annual research and monitoring to document changes to subsistence patterns and harvest levels resulting from the proposed project.

Studies commissioned as part of the GMT2 development will be designed with input from the community and will identify changes resulting from the proposed project including cumulative effects, and, at a minimum, monitor impacts to caribou, fish, and bird harvests. Monitoring reports, aggregated harvest data, and overall use areas by resource will be made available to local residents and the public via the standards established by the Data Review and Information Dissemination mitigation measure (Section 4.4.2.5).

Researchers will employ adaptive research and monitoring techniques, including flexibility to refine monitoring questions based on study findings on a year-to-year basis. Adaptive monitoring will include researcher discretion to establish or reformulate local resource expert panels.

The methodology for the monitoring studies will be approved by the North Slope Borough Department of Wildlife Management (NSB DWM) and the NSB DWM will conduct annual initial peer review of the monitoring reports. The reports will be edited according to the NSB DWM peer review and the subsequent draft report will be provided simultaneously to the permittee and, when appropriate, to a local resource panel (e.g., the Nuiqsut Caribou Panel). The contractor will incorporate comments from both entities before releasing a final report.

*Potential Benefits and Residual/Unavoidable Impacts:* A subsistence monitoring study would help identify the impacts of GMT2-related activities on Nuiqsut subsistence activities. The nine years of data from the Nuiqsut subsistence caribou monitoring project (SRB&A 2010a-2018) is a valuable resource for evaluating impacts. The permittee may expand upon the Nuiqsut Caribou Subsistence Monitoring Project (initiated in 2008 and proposed for a total length of 10 years) to include additional resources (e.g., birds, fish) and to document both impacts related to GMT2 and cumulative impacts. The monitoring program would continue on an annual basis until 2024 and on a biennial basis after that. The Subsistence Fishery Monitoring on the Colville River project may be expanded to include Fish Creek and extended on a biennial basis. After 2033, the Authorized Officer and the permittee may agree to adjust the focus and duration of these subsistence monitoring studies. The results of an expanded subsistence monitoring project could be used to develop future mitigation measures aimed at lessening the impacts of GMT2 on Nuiqsut harvesters. Subsistence monitoring studies will continue throughout the life of the project, or until the Authorized Officer determines such studies are no longer necessary or prudent.

## Potential Mitigation Measure 7: Road Pullouts and Access Ramps along the GMT2 Road

**Objective**: To ensure the GMT2 road pullouts are constructed in advantageous locations and that ramps constructed to provide ATV access to and from ground surface are designed to allow maximum benefit to local users and to protect tundra damage.

**Requirement/Standard:** Prior to construction of the GMT2 Access Road, the permittee will hold a public workshop in Nuiqsut to gather input regarding the location and design of the three road pullouts and associated access ramps. Information from the workshop will be used by the permittee to ensure that the pullouts are properly located along the road to maximize access for subsistence users. The access ramps should be long and wide enough to allow safe ingress and egress to and from the road and/or pullout. In addition, the design of the ramps should account for multi-season subsistence-use while minimizing impacts to the adjacent ground surface. This may involve "hardening" of the tundra around the bottom of the ramps with geo-block or other acceptable methods.

Once the road pullouts and access ramps have been designed, the permittee will post the design for public comment for 30 days. Input derived from the public workshop and comment period will be provided to the BLM and the Kuukpik Subsistence Oversight Panel (KSOP). Concurrence from KSOP on final location and design of the pullouts and ramps shall be obtained by the permittee.

At least once a year after construction, the permittee will hold a public meeting in Nuiqsut to discuss use of the access road, pullouts, and ramps to solicit information on their use and any improvements that could be made to address health, safety, and access concerns. Information gathered at these meetings will be provided to BLM and KSOP, along with any planned improvements.

**Potential Benefits and Residual/Unavoidable Impacts:** Allowing potential users of the pullouts and access ramps a role in ramp location and design will ensure that the ramps provide a locally accepted mechanism for leaving the road surface and accessing tundra that is safe, feasible, and can minimize impacts to subsistence access and aid in search and rescue missions. Regular meetings with local resident who use the road will facilitate improved design features or other suggestions that can be incorporated to make use of the road, pullouts, and ramps safer and more effective for users and prevent tundra damage.

### Potential Mitigation Measure 8: Subsistence User Monitoring and Adaptive Management

**Objective:** Prevent or minimize unreasonable conflicts between subsistence users and permitted activities associated with construction, operation, and production at the GMT2 development.

**Requirement/Standard:** Permittee will work with the Native Village of Nuiqsut, the Kuukpik Subsistence Oversight Panel, and local hunters to create a Subsistence User Monitoring Plan. The plan will include documentation of current issues facing subsistence users regarding resource abundance, limitations on access, and resource availability resulting from GMT2 and associated activities, and including other permitted activities being carried out by the permittee in the NPR-A (i.e., exploration drilling, data collection, etc.). The plan will specify a set of key indicators to be monitored through the life of the GMT2 development, as well mechanisms identified by subsistence hunters that can be used to prevent, reduce, alleviate, or correct adverse effects. The monitoring plan will provide a framework for Nuiqsut entities, the permittee, and BLM to adaptively manage impacts to subsistence users resulting from the development. The process for developing the monitoring plan must be approved by the Kuukpik Subsistence Oversight Panel, and the final plan must be approved by the Nuiqsut trilateral entities (NVN, Kuukpik Corporation, and City of Nuiqsut).

**Potential Benefits and Residual/Unavoidable Impacts:** Current subsistence monitoring in Nuiqsut focuses on the subsistence harvest, namely the scope and amount of resources being harvested through time, and only peripherally documents issues being experienced by the users themselves. Local residents have expressed frustration at the pace of development, the lack of in-depth data regarding impacts, and the inadequacy of back-to-back NEPA analyses in effectively describing and minimizing risk. Establishing a monitoring plan and program now at the beginning of development activities in NPR-A

will help inform future analyses and development decisions. Combining the monitoring plan with adaptive management actions will afford local residents a measure of control over subsistence use.

### Potential Mitigation Measure 9: Prohibit Airboats in Key Subsistence Use Areas*

**Objective**: To reduce noise and disturbance impacts from airboats on subsistence resources, users, and activities.

**Requirement/Standard:** Except in the case of emergencies, oil spill response training, mobilization and deployment of pre-staged spill response equipment, and mobilization and response during a spill event, the permittee and its contractors will be prohibited from using airboats on rivers on BLM managed lands in the Nuiqsut subsistence use area (for this measure, defined as a 50-mile-wide buffer around the community). Through consultation with local residents, BLM may identify other key boating areas that should be avoided. The Authorized Officer and the permittee will coordinate to identify specific areas/rivers where oil spill response training and preparation activities would be permitted by BLM.

**Potential Benefits and Residual/Unavoidable Impacts**: Prohibiting the use of airboats in places where residents are actively traveling by boat to harvest subsistence resources will reduce potential disruptions to subsistence users and resources. The sudden and loud noise of airboats causes acute stress situations for subsistence users, particularly the elderly. Residual issues could arise if local subsistence use of airboats increased (there is currently one airboat, not in use, in Nuiqsut). The BLM would not have the authority to implement this measure on non-BLM managed land and it is therefore unlikely that hunters and other subsistence users will experience complete respite from airboat disturbance if the measure is not adopted by the permittee for other lands.

### Potential Mitigation Measure 10: Annual Community Ice Road Information

**Objective:** Provide the community of Nuiqsut with information on area ice roads on an annual basis

**Requirement/Standard:** Before ice road construction begins, the permittee and contractors associated with ice road construction will hold a community meeting to describe the routes and relevant information on all ice roads that will be constructed within the GMT2 project area. At the meeting, the permittee will distribute copies of maps of that winter's ice roads. The permittee will also make the map available on the website developed to comply with Sociocultural potential mitigation measure #1 (if that measure is adopted as a BMP in the ROD for GMT2) and provide notice of availability of the map and a link to the online map on local social media (i.e., the Nuisagmiut facebook group).

**Potential Benefits and Residual/Unavoidable Impacts**: Community members have no official system for learning about where ice roads are being constructed each winter and whether there are any relevant restrictions on those roads. Many winter hunters use the roads to facilitate access to hunting areas, and some may need to plan the locations for trap lines and other subsistence activities that could be affected by ice roads. This measure, if adopted, would only apply to ice roads within the GMT2 project area, which does not adequately address the needs of the community. The permittee is therefore encouraged to include information on all ice roads within 40 miles of Nuiqsut.

## Proposed New Mitigation Measures for Public Health

### Potential Mitigation Measure 1—Minimize Undue Idling of all Vehicles

**Objective:** Reduce air emissions and protect human health.

**Requirement/Standard:** To the extent practicable, engines of rolling stock (such as pick-up trucks, vans, buses, other trucks and trailers, and heavy machinery) used for oil and gas operations will be powered off when not in active use.

**Potential Benefits and Residual/Unavoidable Impacts:** Prohibiting unnecessary vehicle idling will reduce emissions associated with vehicle use, such as carbon monoxide, fine particulate matter, and volatile organic compounds. Additionally, this measure will decrease noise impacts associated with the GMT2 Project. Projected emissions associated with GMT2, including vehicle exhaust emissions, are subject to the regulatory oversight ofthe Environmental Protection Agency through emission standards for engines and vehicles.

### Potential Mitigation Measure 2—Public Health Monitoring

**Objective:** To understand the effects of oil and gas development-related changes to population health and increase community understanding of public health impacts.

**Requirement/Standard:** The Human Health Baseline Summary (Appendix G) provides an overview of and helps establish the current health status of the communities within the North Slope Borough. Future human health baseline summaries can be created to make comparisons to baseline summaries over-time and as oil and gas development may advance within NPR-A. Future human health baseline studies may include health indicators and and should focus on health outcomes and/or health determinants that can be tied to GMT2 oil and gas activity. Where possible, indicators should include threshold levels and specific actions should be developed for when thresholds are surpassed. The State of Alaska Department of Health and Social Services, the North Slope Borough, and the Alaska Native Tribal Health Consortium should be consulted in the identification of appropriate indicators, thresholds, and responsive actions.

**Potential Benefits and Residual/Unavoidable Impacts:** Future comparisons to the Human Health Baseline Summary (Appendix G) may expedite the detection of changes in population health caused by GMT2 development and associated oil and gas activity. Future human health baseline information may inform on-going health monitoring activities to help further understand public health changes that may result from oil and gas development.

### Potential Mitigation Measure 3—Water Quality Monitoring

**Objective:** Ensure that permitted activities do not create a human health risk through contamination of local drinking water sources.

**Requirement/Standard:** Permittee will work with the City of Nuiqsut to design and implement a water quality monitoring program at the fresh water drinking lake, and other lakes in the vicinity that could be used as a source of drinking water should the currently utilized lake fail or become contaminated. The monitoring program will consist of a monitoring plan, training for local residents so that they can carry out the monitoring themselves, and a water sampling program.

**Potential Benefits and Residual/Unavoidable Impacts:** Monitoring the fresh water sources used for drinking water in Nuiqsut will provide information on contaminant levels, if present, which may have the potential to affect drinking water quality and human health.

### Potential Mitigation Measure 4—Accident Prevention: Additional Requirement to BMP C-3

**Objective:** Prevent accidents due to snowmachine operators trying to cross ice road bridges after they have been removed, breached or slotted in accordance with BMP C-3

**Requirement/Standard:** Crossing of waterway courses shall be made using a low-angle approach. Crossings that are reinforced with additional snow or ice ("bridges") shall be removed, breached or slotted before spring break-up. Trails leading to the snow or ice bridge shall be clearly marked on either side of the crossing once it has been removed, breached or slotted. Applicant will coordinate with local entities (Kuukpik, NVN, City of Nuiqsut) to establish the best way to mark and communicate to Nuiqsut residents when the ice bridges are no longer passable.

**Potential Benefits and Residual/Unavoidable Impacts:** Clearly marking trails on either side of a crossing that has been removed, breached or slotted will ensure that local users as well as contractors are aware that the trail has been compromised and that the crossing should not be used, thereby minimizing the likelihood of an accident.

## Proposed New Mitigation Measures for Solid Waste and Hazardous Materials

### Potential Mitigation Measure 1 —Trash Removal and Anti-Littering Campaign

**Objective***:* Prevent unnecessary or undue degradation of the land.

**Requirement/Standard:** All solid waste and industry-derived trash originating from permitted activities is required to be properly containerized while on site, or removed from the area of operation/activity. Objects that have the potential to be left or forgotten (such as duck ponds, containments, or sorbent material caches) shall be clearly marked with the name of the company using the object.

The permittee will solicit ideas from the community of Nuiqsut to assist with addressing regular trash removal and inadvertent littering (including such things as ice-roads delineation markers, construction detritus, etc.) in order to ensure or adopt cost-effective methods that also minimize other identified impacts, such as those associated with helicopter use.

**Potential Benefits and Residual/Unavoidable Impacts:** Clearly marking movable objects associated with industrial development with the name of the company who utilized them will instill a greater sense of responsibility in employees in being good neighbors and ensuring the objects are not left or forgotten. In addition, it will also allow the permittee, the BLM, and local residents to track and assess the effectiveness of workers or contractors in following authorization requirements. By working with the community to identify new ideas or suggestions for the removal and handling of trash, the permittee may be able to save money while building effective partnerships.

### Potential Mitigation Measure 2 —Leak Detection and Leak Shut Down Requirements

**Objective***:* Reduce pipeline leaks and protect human health and safety.

**Requirement/Standard:** Meet the requirements of 18 AAC 75.055 for the pipeline carrying crude oil from GMT2 to GMT 1, including using external leak detection for prompt identification of leaks, daily flow verification, weekly visual surveillance, and demonstrated ability to stop flow within one hour of detection.

**Potential Benefits and Residual/Unavoidable Impacts:** The pipeline carrying crude oil from GMT2 to GMT1 is a flow line regulated under 18 AAC 75.047. Although it does not meet the definition of a crude oil transmission pipeline because it also carries gas and produced water, complying with the 18 AAC

75.005 requirements for crude oil transmission pipelines will ensure early detection and response to any leaks. This will minimize impacts to human health and the environment from pipeline leaks.

### Potential Mitigation Measure 3—Fuel Storage (new subparagraph to BMP A-4)

**Objective:** Minimize the impact of contaminants on fish, wildlife, and the environment, including wetlands, marshes, and marine waters, as a result of fuel, crude oil, and other liquid chemical spills. Protect subsistence resources and subsistence activities. Protect public health and safety.

**Requirement/Standard:** Fuel and hazardous material storage containers with a capacity greater than 660 gallons must use impermeable lining and diking capable of containing 110 percent of the containers' capacity. Vinyl liners, with foam dikes and a capacity of 25 gallons, must be placed under all valves or connections to fuel tanks when located outside of secondary containment.

**Potential Benefits and Residual/Unavoidable Impacts:** Potential benefits of these added measures above current protections include additional protection for vegetation, wetlands, and other surface resources by l providing secondary containment for storage containers greater than 660 gallons and using liners for protection outside of secondary containment.

### Potential Mitigation Measure 4— Oil Spill Response Equipment (new subparagraph to BMP A-3)

**Objective:** Minimize pollution through effective hazardous-materials contingency planning.

**Requirement/Standard:** Oil spill response equipment for use in winter conditions must meet the following standards:

a. Equipment must be designed to be effective in Arctic conditions.

b. Mechanisms must be available to prevent the freezing of response equipment (including the equipment used for storing, transferring, and treating recovered fluids) and/or to de-ice it.

**Potential Benefits and Residual/Unavoidable Impacts:** Potential benefits of these added measures above current protections include additional protection for vegetation, wetlands, and other surface resources by ensuring response equipment is operational under extreme weather conditions and other limiting factors such as ice and snow conditions.

### Potential Mitigation Measure 5—Facility Equipment and Design Criteria (new subparagraph to BMP A-3)

**Objective:** Minimize pollution by ensuring adequate facility design criteria and system integrity.

**Requirement/Standard:** Equipment used to develop hydrocarbons must meet the following standards:

a. Equipment must be designed in accordance with standard Arctic engineering practices for use in Arctic conditions;

b. Design criteria must be based on conservative estimates (as determined by the authorizing officer).

**Potential Benefits and Residual/Unavoidable Impacts:** System integrity is essential for spill prevention, but not all integrity requirements are within the scope of Oil Spill Contingency Planning.

Potential benefits of these added measures above current protections include additional protection for vegetation, wetlands, and other surface resources by ensuring facility design and system integrity are suitable to harsh Arctic environmental conditions.

### Potential Mitigation Measure 6— Leak Detection Criteria (new subparagraph to BMP E-4)

**Objective:** Implement leak detection systems for GMT1 facilities.

**Requirement/Standard:** To the extent practicable, the permittee will provide a specific description of the leak detections systems installed on all lines described in the development plan. The descriptions could be an addendum to the Alpine C-Plan or a stand-alone document. Monitoring would be via remote continual monitoring (e.g., camera or FLIR) of water crossings, or daily on-site visual inspections. The spill prevention section of the Alpine C-Plan must contain criteria to prevent and detect slow leaks.

**Potential Benefits and Residual/Unavoidable Impacts:** Automated and visual on-site leak inspections would reduce the extent of spills.

# APPENDIX R

# APPLICANT PROPOSED 404 MITIGATION PLAN

# GREATER MOOSES TOOTH TWO (GMT2) DEVELOPMENT PROJECT PERMITTEE RESPONSIBLE WETLANDS MITIGATION PLAN

# NATIONAL PETROLEUM RESERVE-ALASKA

*Prepared for:*
ConocoPhillips Alaska, Inc.
Anchorage, AK

ConocoPhillips

**August 2018**

*This page intentionally left blank.*

## TABLE OF CONTENTS

## APPENDICES

### Appendix



## TABLES

# ACRONYM LIST

| | |
|---|---|
| ABR | ABR, Inc.- Environmental Research & Services |
| ANSRAM | Alaska North Slope Rapid Assessment Method |
| ASA | Aquatic Site Assessment |
| ASRC | Arctic Slope Regional Corporation |
| CPAI | ConocoPhillips Alaska, Inc. |
| DA | Department of the Army |
| FCI | Functional Capacity Index |
| GMT 2 | Greater Mooses Tooth 2 |
| HDL | Hattenburg Dilley & Linnell |
| HUC | Hydrologic Unit Code |
| NSB | North Slope Borough |
| NWI | National Wetland Inventory |
| PRM | Permittee Responsible Mitigation |
| USACE | U.S. Army Corps of Engineers |
| USFWS | United States Fish and Wildlife Service |
| WOUS | Waters of the U.S. |

*This page intentionally left blank.*

# 1.0 INTRODUCTION

ConocoPhillips Alaska, Inc. (CPAI) is seeking a Department of the Army (DA) permit authorization from the U.S. Army Corps of Engineers (USACE) to construct the Greater Mooses Tooth Two (GMT2) development project, consisting of a drill site, access road, pipelines, and ancillary facilities to support development of petroleum reserves within the Greater Mooses Tooth Unit. The proposed work involves the placement of clean fill material on 78.1 acres, 77.9 acres of which are Waters of the U.S. (WOUS). A Vicinity map showing the location of the GMT2 Project is included in Appendix A, Figure 1.

# 2.0 OBJECTIVES

The overall objective of this Permittee Responsible Mitigation (PRM) plan is to demonstrate how CPAI proposes to mitigate for unavoidable wetlands impacts at GMT2 through permittee responsible wetlands restoration. In addition to the avoidance and minimization measures incorporated into the design of GMT2, the proposed restoration project presented in this PRM plan provides wetlands uplift near the GMT2 project site. The mitigation project will restore important key functions to a riverine wetland system associated with a fresh water access road (Fresh Water Road) in Nuiqsut, Alaska. In addition, the project will provide safe and continuous access to Nuiqsut's fresh water supply reservoir. Safe and continual access to the reservoir is currently jeopardized by recurring flooding and road damage that occurs during breakup.

The current culvert battery crossing associated with the Fresh Water Road is undersized, resulting in ice damming and road over-topping during spring breakup flood events. The gravel road prism over the culverts has been significantly damaged from the over-topping and is contributing to gravel deposition and excess sediment load to the riverine system. The undersized culverts and altered flows contribute to degraded aquatic function and alter the system's hydrologic and sediment transport functions.

The Fresh Water Road restoration project will restore important key riverine wetland function to 35.8 acres (0.30 acres more than currently exists) of lower perennial stream and abutting palustrine wetlands, as well as alleviate ice damming associated with annual breakup discharges. This functional uplift will be achieved through restoring natural flows by: 1) upgrading the crossing to reflect normal flow conditions to restore flood flow alteration function and improve general habitat suitability; 2) removing gravel that has washed downstream to improve sediment removal function and afford vegetation growth; and 3) elevating the road crossing above anticipated spring breakup flood elevations to protect from road washouts during breakup. This restoration project would provide direct benefit to a resident fish bearing stream and abutting wetlands that discharge directly to the Nigliq Channel of the Colville River. These improvements would protect a crucial Nuiqsut transportation corridor providing access to Nuiqsut's fresh water supply. A Restoration Site Overview Map is included in Appendix A, Figure 2.

## 3.0 SITE SELECTION

The proposed Fresh Water Road restoration site is in the village of Nuiqsut, Alaska, and is identified on the Vicinity Map (Figure 1) and Overview Map (Figure 2) in Appendix A.

The North Slope Borough (NSB) contracted Hattenburg, Dilley, and Linnell (HDL) to complete a Project Analysis Report (PAR) (Appendix B) for the crossing in 2016 (HDL 2016). HDL reported that the crossing appears within the floodplain of the Colville River and that it has undersized culverts which result in the roadway getting over-topped during high spring breakup flows.

The factors considered during the mitigation site selection process include the following:

- Watershed and community needs;
- Onsite alternatives;
- Other restoration alternatives or land preservation opportunities near the watershed; and
- Practicability of accomplishing an ecologically self-sustaining mitigation project.

### 3.1 Watershed Needs

The GMT2 impacts occur along the drainage divide between the following 10-digit Hydrologic Unit Code (HUC) watersheds:

- 1906020507 - Outlet Fish Creek
- 1906020506 - Ublutuoch River

The Outlet Fish Creek watershed occupies 137,576.89 acres, and the Ublutuoch River watershed occupies 150,954.37 acres. The GMT2 project will impact 52.3 acres of wetlands in the Outlet Fish Creek, and 25.6 acres of wetlands in the Ublutuoch River watersheds, for a total of 77.9 acres of wetlands impacts. These two watersheds contain very little current development and are made up almost entirely of jurisdictional WOUS, including wetlands. The total current development and proposed GMT2 development in these watersheds will be 88.9 acres and 90.1 acres, respectively (Figure 3, Appendix A). This is equivalent to 0.06 percent total anthropogenic impacts in each of the 10-digit HUCs; therefore, these watersheds are not considered impaired.

The proposed restoration project is in the adjacent Colville River Delta-Frontal Harrison Bay watershed (HUC-1906030413). This watershed occupies 303,614.25 acres and contains the village of Nuiqsut and the gravel infrastructure development associated with the village, transportation corridors, and gravel mining. The immediate area around Nuiqsut and the mitigation project site drain to the Nigliq Channel of the Colville River, an important subsistence resource for the area. CPAI has consulted the NSB to discuss the needs of Nuiqsut and the importance of completing this project. The proximity of the mitigation site to Nuiqsut creates an opportunity to provide wetlands and water-related

benefits to the community that is nearest to the GMT2 project and to wetland and water resources used by the community. A copy of the letter agreement documenting CPAI's discussions with the NSB is provided as Appendix C to this Mitigation Plan.

### 3.2 Onsite Alternatives

Mitigation opportunities at the GMT2 project site were considered, but the lack of development in the abutting and adjacent wetlands affords no opportunities for wetlands restoration, or creation onsite or in the same watershed. As shown on Figure 3 (Appendix A), these two watersheds would only have 0.06 percent anthropogenic impacts from development after GMT2 is constructed.

### 3.3 Other Restoration Alternatives or Land Preservation Opportunities

Other options were explored but nothing was identified that had a similar combination of proximity to the GMT2 project area, actual wetlands functional uplift, positive community impact and community support, and economic practicability. Land preservation opportunities were explored but are very limited, provide no wetlands uplift, are commercially complex, and lack the broad support of a restoration program.

### 3.4 Practicability of Results Being Ecologically Self-Sustaining

The proposed improvements to the Fresh Water Road will follow acceptable practices of arctic engineering and design. Regular monitoring, coupled with routine maintenance activities and returning the riverine system to normal flows, will result in an ecologically self-sustaining restoration project.

## 4.0 SITE PROTECTION INSTRUMENT

CPAI has discussed this mitigation project with the NSB. CPAI does not own the land proposed for restoration activities and does not have the ability to establish a perpetual protection instrument. The site is managed by the local government (NSB). The mitigation project does not face threats that are deemed to require site protection beyond the stewardship provided by the NSB.

## 5.0 BASELINE INFORMATION

### 5.1 GMT2 Baseline Information

ABR, Inc. - Environmental Research & Services (ABR) performed wetlands habitat mapping for the GMT2 project and submitted that information to CPAI in a July 2017 wetland delineation and desktop mapping verification report (ABR, 2017). The ABR report (Appendix D) contains detailed wetlands mapping and habitat descriptions for the proposed GMT2 impact area, which is included in a larger immediate study area investigated by ABR.

ABR reported that the GMT2 study area contains typical tundra habitats composed of dwarf shrub and emergent vascular plants within saturated and seasonally flooded palustrine wetlands. The study area also comprises two shallow open-water pond systems with poor littoral zones. ABR stated that the pond systems are likely remnants of drained lake basins, which are prevalent on the North Slope.

The ABR report concludes that the GMT2 project will impact 77.8 acres (rounded to the nearest 0.1 acre) of palustrine wetlands and a 0.1-acre pond habitat for a total of 77.9 acres of jurisdictional WOUS impacted. ABR reports that the GMT2 project will also impact 0.2 acres of non-jurisdictional uplands.

CPAI performed an Aquatic Site Assessment (ASA) based on the Arctic Slope Regional Corporation (ASRC) Alaska North Slope Rapid Assessment Method (ANSRAM) for each wetlands class impacted by the GMT2 project to determine the baseline level of functional capacity and the post-project impacts to those watershed functions after GMT2 is constructed. ANSRAM determined that the key functions being provided by the wetlands prior to constructing GMT2 are:

- Flood flow alteration;
- Nutrient and toxicant removal;
- Production of organic matter and its export;
- General habitat suitability; and
- Native plant richness.

The overall baseline Functional Capacity Index (FCI) score for each wetland class is shown below in Table 1.

**Table 1. GMT2 Baseline FCI Scores**

| Wetlands Class | FCI Score | Acres |
|---|---|---|
| PEM1F | 0.781 | 4.3 |
| PEM1SS1B | 0.682 | 49.8 |
| PEM1SS1E | 0.799 | 23.7 |
| PUBH | 0.814 | 0.1 |

0.0 = Low Functional Capacity/ 1.0 = High Functional Capacity

The overall FCI scores determined by ANSRAM for each wetlands type after GMT2 construction are shown below in Table 2. The FCI scores indicate that while permanent gravel will be placed for the construction of GMT2 and result in reduced wetland function, the loss of function in the watershed will be partial rather than total because of the minimization measures incorporated into the GMT2 project, such as culverts to preserve water flow and sufficient gravel to minimize thermokarsting.

**Table 2. Post GMT2 FCI Scores**

| Wetlands Class | FCI Score | Acres |
|---|---|---|
| PEM1F | 0.618 | 4.3 |
| PEM1SS1B | 0.542 | 49.8 |
| PEM1SS1E | 0.677 | 23.7 |
| PUBH | 0.710 | 0.1 |

0.0 = Low Functional Capacity/ 1.0 = High Functional Capacity

Copies of the ANSRAM data sheets showing the individual evaluation metrics and the individual FCI for each function are included in Appendix E.

## 5.2 Fresh Water Road Restoration Site Baseline Information

A formal wetland delineation has not been completed for the Fresh Water Road restoration site. The wetlands proposed for restoration were delineated from the desktop using United States Fish and Wildlife Service (USFWS) National Wetland Inventory (NWI) mapping (USFWS, 2017). NWI mapping was further adapted using current aerial photography and information contained within the 2016 PAR. The extent of the desktop mapping is depicted in Appendix A, Figure 2.

The desktop delineation indicates the Fresh Water Road restoration site currently consists of 35.5 acres of lower perennial riverine habitat (mapped to 20 foot above mean sea level), with palustrine emergent littoral zones and inclusions (R2EM2/UBH). The upstream portion of the system is delineated to the approximate extent of estimated maximum annual breakup flooding elevation presented in the 2016 PAR. The downstream portion of the restoration site terminates at another culvert crossing.

The 2016 PAR identified the restoration site as a culverted crossing over a series of kettle ponds that provides access to the community's water supply located 1.2 miles south of Nuiqsut. HDL reported that a 16-foot wide gravel roadway crosses the unnamed drainage. HDL also reported that the culverts were installed after an existing bridge failed. The crossing consists of three 48-inch diameter by 40-foot long galvanized corrugated steel culverts, armored at the inlets and outlets with sandbags. The crossing primarily drains 9.5 square miles and conveys snowmelt and permafrost thaw. The stream has a mild hydraulic gradient of 0.4% and connects with the main channel of an unnamed stream that is approximately 500 feet downstream of the road crossing. The unnamed stream drains to the Nigliq Channel of the Colville River. HDL reported that the road crossing at the proposed restoration site experiences regular over-topping caused by high spring breakup flows, ice damming, and currently undersized culverts.

This flooding has contributed to road damage which results in excess gravel and sediment deposition downstream of the crossing. This deposition has resulted in channel constriction

downstream of the culverts and removal of shoreline vegetation and wetlands habitat. Additional impacts resulting from repeated inundation may be experienced upstream to the limit of reported flood elevations. The upstream portion also discharges from Nuiqsut airport; therefore, flooding could jeopardize the runway during spring breakup.

CPAI performed a baseline desktop ASA for the site using the ASRC ANSRAM to be consistent with the ASA performed for the GMT2 impact site. The ANSRAM determined that the key functions currently being provided by the riverine systems are:

- Nutrient and toxicant removal;
- General fish habitat;
- Native plant richness; and
- Production of organic matter and its export.

ANSRAM determined that several functions were underperforming due to the condition of the culverts and the gravel deposition downstream from annual flood events. The functions that are underperforming and in need of uplift are:

- Sediment removal;
- Erosion and shoreline stabilization;
- General habitat suitability;
- Educational value; and
- Uniqueness and heritage.

ANSRAM determined that the overall baseline FCI score for the system is 0.651.

ANSRAM determined that addressing the issues at the crossing would provide significant uplift to the degraded functions listed above, and that the post-restoration project would result in an overall FCI score of 0.947, which is a ~45 percent increase in function across the system. Additionally, the restoration project would add 0.30 acres to the system by returning the crossing to normal flow patterns and removing gravel deposited downstream.

The ANSRAM data sheets showing the pre- and post-restoration site functional capacity for each measured function are included in Appendix E.

Photographs of the restoration site taken during the summer of 2017 are below:

**Photo 1**. View along roadway and crossing, looking south.

**Photo 2**. View along roadway and crossing, looking north.

**Photo 3**. View looking south at upstream side of culverts.

**Photo 4**. Looking north at downstream side of culverts. The gravel in the stream is from road washouts.

**Photo 5**. View of upstream side of culverts and sand bag armoring in creek and road embankment.

**Photo 6**. View downstream from road surface with gravel in stream.

# 6.0 MITIGATION CREDIT

The Fresh Water Road restoration project would benefit 35.8 acres of lower perennial stream channel and abutting wetlands. Mitigation would be provided by removing the gravel that has been washed downstream and restoring the crossing to natural flow conditions. The crossing restoration will involve widening the stream to its pre-disturbance ordinary high-water width. The restoration project will provide an approximate 0.30-acre increase in wetland surface area over the existing 35.5-acre habitat. The gravel removal will allow shoreline palustrine wetlands to form.

Road integrity will be restored by strengthening the embankments and raising the road grade above anticipated flood elevations, which will reduce the existing effects that the road has on the channel. Upstream channel deformation will likely subside given that excessive ponding from ice damming would be mitigated. Sediment transport function downstream will also be realized once natural flows and channel dimensions are restored at the crossing.

CPAI used the FCI score from ANSRAM to determine a debit from GMT2, using the USACE Credit-Debit Procedure. The debit-credit calculation determined that GMT2 would result in 10.5 debits and that the restoration site would result in 10.7 credits, thus returning slightly more than a 1:1 mitigation ratio. A copy of the calculation is included in Appendix E.

# 7.0 MITIGATION WORK PLAN

## 7.1 Fresh Water Road Restoration Work Plan

CPAI proposes to enter into a contractual agreement with the NSB and plans to complete the Fresh Water Road restoration project within the time frame that GMT2 is constructed, which is estimated to be complete by October 2021. The work will include removal of the existing culvert battery and restoring the stream to normal flow patterns. The actual design of the crossing is estimated to be complete by December 31, 2018 and will be submitted to the Corps as an addendum to this PRM plan by March 31, 2019.

The nature of the work and soils in the area lend themselves to construction during multiple seasons. CPAI will mobilize and demobilize materials and equipment for all construction activities. Ice roads will be used during winter activities. CPAI will work closely with the NSB and Nuiqsut for specific construction activity timing.

The excess gravel deposited downstream due to recent flood events will be removed as part of this effort. The gravel, depending on the quality, could be reused in road grade improvements. Gravel that cannot be used will be deposited in an upland location. Vegetation along the shoreline will be allowed to develop naturally where gravel is removed.

# 8.0 MAINTENANCE PLAN

Land at the Fresh Water Road restoration site is owned and managed by the NSB. The NSB will be responsible for all maintenance at the site after the repair is completed.

# 9.0 PERFORMANCE STANDARDS

The design will restore normal flows and remove the excess sedimentation downstream of the crossing. Upstream portions of the stream will experience a reduction in flood elevations and ice damming during breakup. This will alleviate the potential for shoreline erosion and ice gouging. Scour below the crossing will be mitigated by restoring normal flow patterns.

Importantly, an improved crossing would also provide year-round community access to the fresh water supply south of the crossing. The threat of flooding to the airport runway will be reduced. Any other use of the road crossing, such as for access to subsistence or recreational activities, will also be improved.

Other design and performance standards will be established by agreement with the NSB.

# 10.0 MONITORING PLAN

CPAI will confirm the efficacy of the repairs during the first breakup season following completion of those repairs. This confirmation will include documentation that the integrity of the road prism and new crossing are maintained and that normal flows are being experienced. The findings from this monitoring effort will be retained by CPAI and used in the determination of whether adaptive management is necessary.

# 11.0 LONG-TERM MANAGEMENT

The NSB will be responsible for all long-term management of the crossing.

# 12.0 ADAPTIVE MANAGEMENT

The NSB will be responsible for any adaptive management at the crossing.

# 13.0 FINANCIAL ASSURANCE

CPAI will ensure that the project, as explained in this document, is executed. The NSB will be responsible for financial assurance related to future maintenance and monitoring.

# 14.0 REFERENCES

ABR, Inc.- Environmental Research & Services (ABR). 2017. Wetland Delineation and Desktop Mapping Verification for the Greater Mooses Tooth 2 Development Project, Alternative A-2015. 2017.

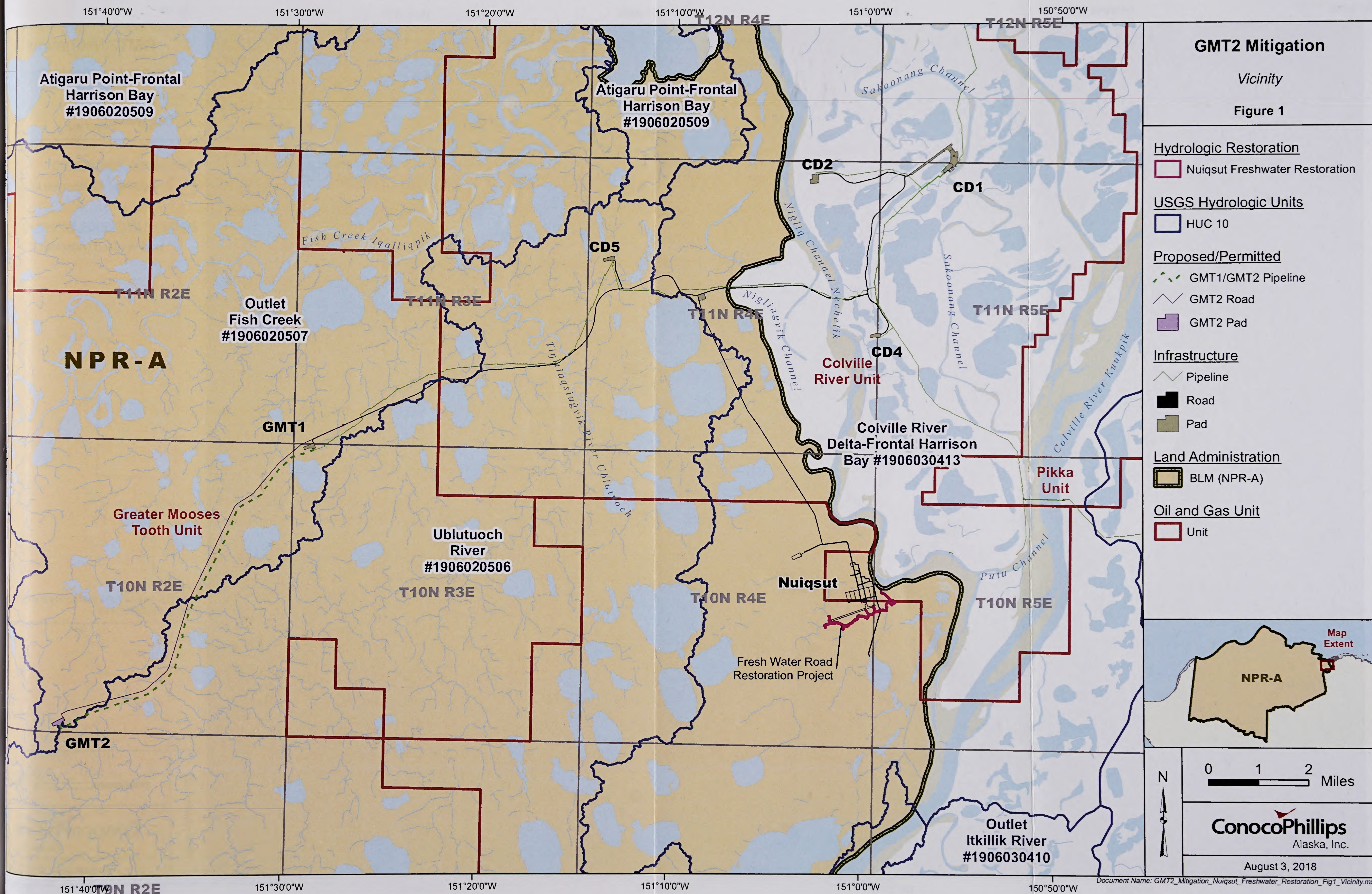
Hattenburg Dilley & Linnell (HDL). 2016. Project Analysis Report, Nuiqsut Repair Bridge Crossings. 2016.

United States Fish & Wildlife Service (USFWS). 2017 Nation.al Wetland Inventory Mapping website. 2017. https://www.fws.gov/wetlands/data/Mapper.html.

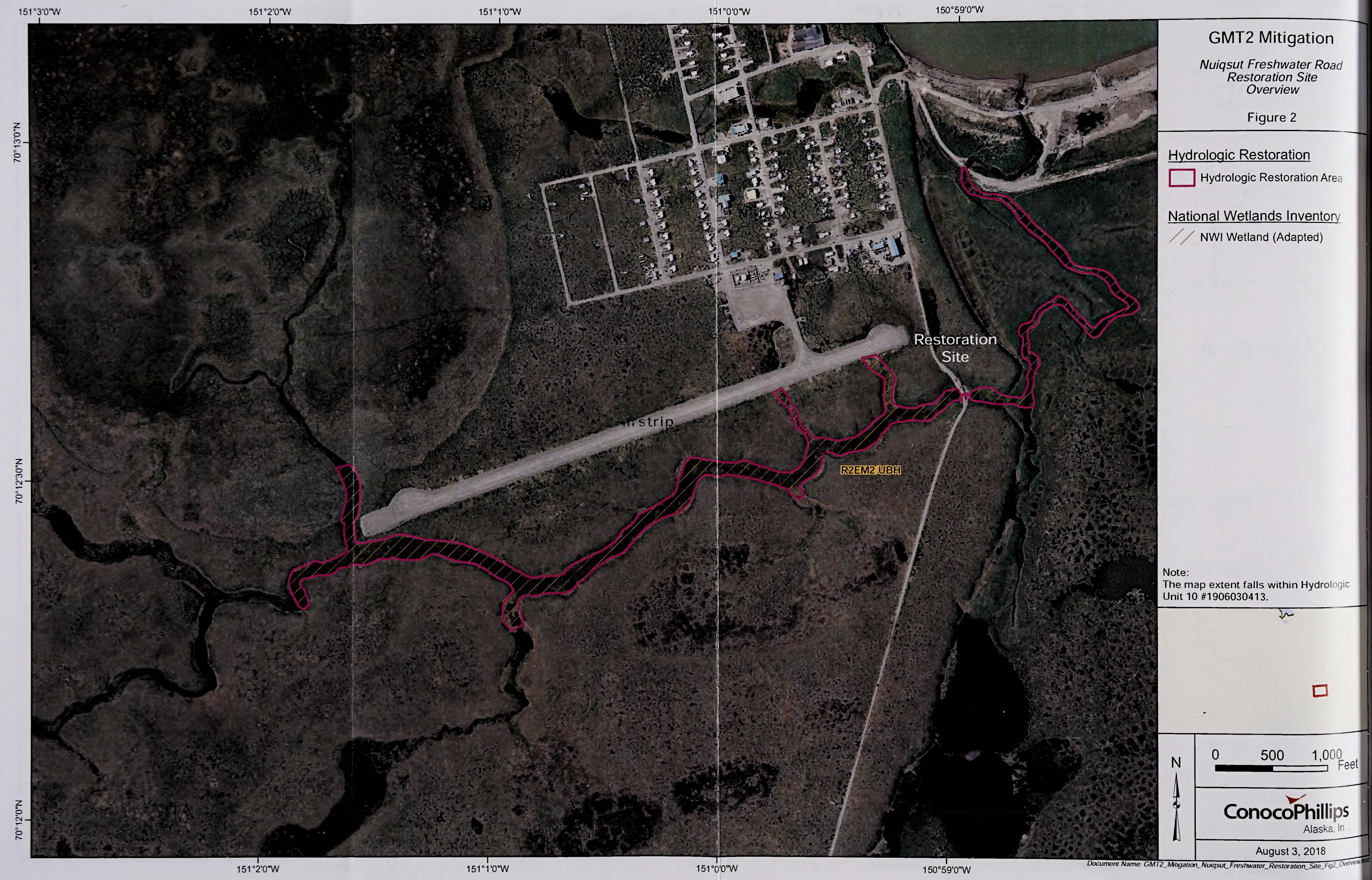
# APPENDICES

*This page intentionally left blank.*

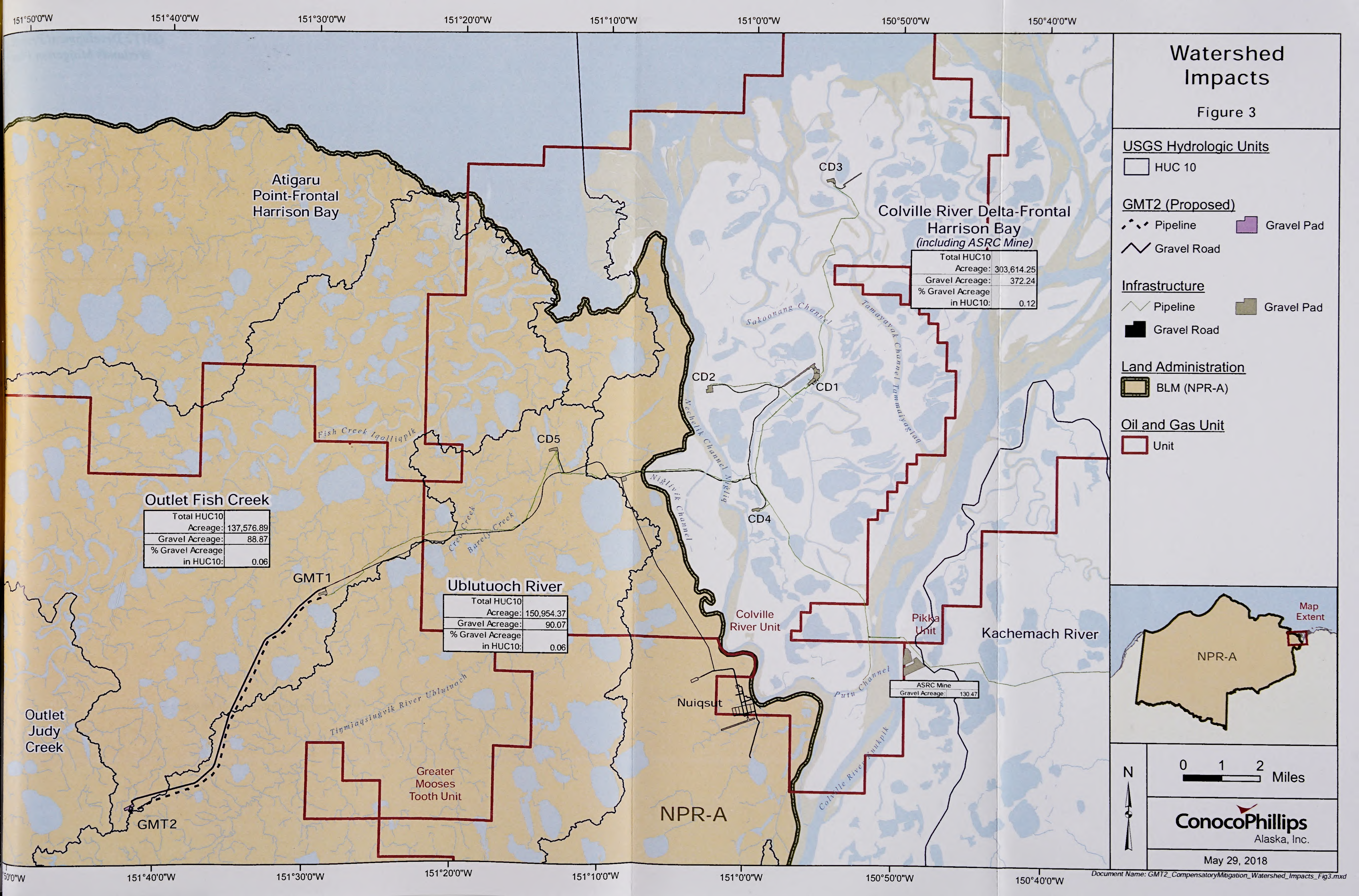
# APPENDIX A
# FIGURES



GMT2 Mitigation
Vicinity
Figure 1
Hydrologic Restoration
Nuiqsut Freshwater Restoration
USGS Hydrologic Units
HUC 10
Proposed/Permitted
GMT1/GMT2 Pipeline
GMT2 Road
GMT2 Pad
Infrastructure
Pipeline
Road
Pad
Land Administration
BLM (NPR-A)
Oil and Gas Unit
Unit
Map Extent
NPR-A
N
0 1 2 Miles
ConocoPhillips
Alaska, Inc.
August 3, 2018
Document Name: GMT2_Mitigation_Nuiqsut_Freshwater_Restoration_Fig1_Vicinity.mxd
151°40'0"W
151°30'0"W
151°20'0"W
151°10'0"W
151°0'0"W
150°50'0"W
T12N R4E
T12N R5E
T11N R2E
T11N R3E
T11N R4E
T11N R5E
T10N R2E
T10N R3E
T10N R4E
T10N R5E
Atigaru Point-Frontal Harrison Bay #1906020509
Atigaru Point-Frontal Harrison Bay #1906020509
Outlet Fish Creek #1906020507
NPR-A
Fish Creek Iqalliqpik
Tinmiaqsiugvik River Ublutuoch
CD5
CD2
CD1
CD4
Sakoonang Channel
Nigliq Channel
Nechelik
Nigliagvik Channel
Sakoonang Channel
Colville River Unit
Colville River Delta-Frontal Harrison Bay #1906030413
Colville River Kuukpik
Pikka Unit
GMT1
Greater Mooses Tooth Unit
Ublutuoch River #1906020506
Nuiqsut
Putu Channel
Fresh Water Road Restoration Project
GMT2
Outlet Itkillik River #1906030410



151°3'0"W
151°2'0"W
151°1'0"W
151°0'0"W
150°59'0"W
70°13'0"N
70°12'30"N
70°12'0"N
Restoration Site
Airstrip
R2EM2 UBH
GMT2 Mitigation
Nuiqsut Freshwater Road Restoration Site Overview
Figure 2
Hydrologic Restoration
Hydrologic Restoration Area
National Wetlands Inventory
NWI Wetland (Adapted)
Note:
The map extent falls within Hydrologic Unit 10 #1906030413.
N
0 500 1,000
Feet
ConocoPhillips
Alaska, In
August 3, 2018
Document Name: GMT2_Mitigation_Nuiqsut_Freshwater_Restoration_Site_Fig2_Overview.mxd


Watershed Impacts
Figure 3
USGS Hydrologic Units
HUC 10
GMT2 (Proposed)
Pipeline
Gravel Pad
Gravel Road
Infrastructure
Pipeline
Gravel Pad
Gravel Road
Land Administration
BLM (NPR-A)
Oil and Gas Unit
Unit
Map Extent
NPR-A
N
0 1 2 Miles
ConocoPhillips
Alaska, Inc.
May 29, 2018
Document Name: GMT2_CompensatoryMitigation_Watershed_Impacts_Fig3.mxd
151°50'0"W
151°40'0"W
151°30'0"W
151°20'0"W
151°10'0"W
151°0'0"W
150°50'0"W
150°40'0"W
Atigaru Point-Frontal Harrison Bay
Colville River Delta-Frontal Harrison Bay (including ASRC Mine)
Total HUC10 Acreage: 303,614.25
Gravel Acreage: 372.24
% Gravel Acreage in HUC10: 0.12
Outlet Fish Creek
Total HUC10 Acreage: 137,576.89
Gravel Acreage: 88.87
% Gravel Acreage in HUC10: 0.06
Ublutuoch River
Total HUC10 Acreage: 150,954.37
Gravel Acreage: 90.07
% Gravel Acreage in HUC10: 0.06
ASRC Mine
Gravel Acreage: 130.47
Outlet Judy Creek
Kachemach River
CD1
CD2
CD3
CD4
CD5
GMT1
GMT2
Nuiqsut
NPR-A
Colville River Unit
Pikka Unit
Greater Mooses Tooth Unit
Fish Creek Iqalliqpik
Crea Creek
Barely Creek
Tinmiaqsiugvik River Ublutuoch
Sakoonang Channel
Tamayayak Channel Tamma(i)yagiaq
Nechelik Channel Nigliq
Nigliq Channel
Putu Channel
Colville River Kuukpik

*This page intentionally left blank.*

# APPENDIX B
# HDL 2016 PROJECT ANALYSIS REPORT

# PROJECT ANALYSIS REPORT

## Nuiqsut Repair Bridge Crossings

**North Slope Borough**
**Department of Public Works**
**Capital Improvement Program Management**


Prepared by: HATTENBURG DILLEY & LINNELL Engineering Consultants

3335 Arctic Boulevard, Suite 100
Anchorage, Alaska 99503


February 10, 2016

# NUIQSUT REPAIR BRIDGE CROSSINGS

## PROJECT ANALYSIS REPORT

**CIP No. 68-041**

**Borough Contract No. 2015-205**

Prepared for:

North Slope Borough
Department of Capital Improvement Program Management
Bernadette Fischer, Program Manager

Prepared by:

Scott Hattenburg, PE/Principal
Adam Bruscher, Project Engineer

Hattenburg Dilley and Linnell, LLC
Engineering Consultants
3335 Arctic Boulevard, Suite 100
Anchorage, Alaska 99503
(907) 564-2120

HDL Project: 15-031-02

February 10, 2016

## TABLE OF CONTENTS

## LIST OF FIGURES



## LIST OF TABLES



## APPENDICES

# EXECUTIVE SUMMARY

The purpose of this study is to provide the North Slope Borough (Borough) with feasible alternatives and costs for the repair and/or replacement of three bridge and culvert crossings in Nuiqsut, Alaska. The three crossings at Sites 1, 2, and 3 have failed or require yearly reconstruction and maintenance.

The Lower Stream Crossing (Site 1) is a temporary culvert crossing approximately 300 feet from the Nigliq Channel. Currently, it provides the only access to the City's boat ramp and material source stockpile. This crossing requires complete reconstruction after the high water and ice jamming events every spring.

The Upper Stream Crossing (Site 2) consists of a 42-foot steel bridge constructed in 1974. This crossing originally provided access to the old airport, and now the village boat ramp and material source stockpile. Reports indicate it failed a couple of years ago. The lower stream crossing at Site 1 was built when the bridge failed.

The Tributary Stream Crossing (Site 3) is a culvert crossing approximately 6,200 feet upstream from the Nigliq Channel that provides the only access to the community's water source. This crossing was installed after a previous bridge failure and has required minimal maintenance with sandbags after seasonal flooding.

Alternatives for each of the crossings were analyzed. Our findings, recommendations and the costs of PAR alternatives are shown **Table EX-1** below.

## FINDINGS

1. All three sites are in the flood plain of the Colville River and are subject to overtopping and ice jamming.
2. Little flood information exists for Nuiqsut and the Corps of Engineers has not established a flood datum for Nuiqsut.
3. A flood study and stream monitoring is needed to determine flood recurrence intervals and flood elevations.
4. Debris lines near Site 2 suggest seasonal floodwaters and ice floes overtop the bridge by approximately 2 feet annually and by approximately 8.5 feet during extreme flood events.
5. The Site 3 culverts are undersized and overtop annually but requires only minor sandbag repair after the high water recedes.
6. Debris lines near Site 3, suggests that the roadway overtops by approximately 4.5 feet during extreme high water events.

## RECOMMENDATIONS

1. Conduct a flood study and stream monitoring study to determine flood recurrence intervals and flood elevations.
2. Conduct a geotechnical investigation to determine engineering and thermal properties of soils at the sites to allow for proper design.
3. At the Lower Stream Crossing (Site 1), remove the crossing after the Site 2 crossing is restored: **Alternative 1A – Remove Crossing and Salvage Useable Materials.**
4. At the Upper Stream Crossing (Site 2), remove the existing bridge and install three 120-inch culverts: **Alternative 2B – New Culverts, Minor Elevation Change.**
5. At the Tributary Stream Crossing (Site 3), install three new 72-inch culverts to provide all-season access to the water source lake: **Alternative 3B – Install New Circular Culverts, Elevate Roadway 3 Feet.**

**Table EX-1 – Capital Cost Summary**

| Alternative | Capital Cost | Useful Life |
|---|---|---|
| 1A. Remove Crossing and Salvage Useable Materials | $203,000 | N/A |
| 1B. Do Nothing | 0 | N/A |
| 2A. New Bridge Crossing, Elevate Above Ordinary High Water | 3,423,000 | 30 years |
| 2B. New Culverts, Minor Elevation Change | 3,216,000 | 30 years |
| 2C. Do Nothing | 406,000 | N/A |
| 3A. Armor Existing Culverts, No Elevation Change | 1,502,000 | 15 years |
| 3B. Install New Circular Culverts, Elevate Roadway 3 Feet | 3,352,000 | 30 years |
| 3C. Install New Arched Culvert, Elevate Roadway 4.5 Feet | 3,932,000 | 30 years |
| 3D. Do Nothing | 0 | N/A |

# 1.0 INTRODUCTION

Hattenburg Dilley and Linnell, LLC (HDL) was retained by the North Slope Borough (Borough) Department of Capital Improvement Program Management (CIPM) to provide a Project Analysis Report (PAR) for the reconstruction of three drainage channel crossings at Nuiqsut, Alaska. The crossings include two culverts and one bridge crossing on the same unnamed drainage. Breakup flood events damage the structures, causing annual repairs and prevent access to the village water source, boat ramp, and material source stockpile.

## 1.1 Project Purpose and Objective

The purpose of this project is to provide the Borough with feasible solutions and costs for the reconstruction of the three drainage channel crossings at Nuiqsut.

## 1.2 Scope

The scope of this PAR includes analyzing the existing site conditions at each of the three sites, developing feasible bridge and culvert crossing alternatives, developing recommendations for repair and/or replacement, and developing a budgetary cost estimate for each alternative. The analysis of the alternatives considers cost, scheduling, phasing of work, material delivery, lead time, impacts on access, and other pertinent criteria determined during the study. HDL worked closely with the Borough and village public works staff to determine the history of failures and operational and maintenance issues.

## 1.3 Project Location

The project sites are located on the village road system at Nuiqsut, Alaska. Nuiqsut is located 35 miles from the Beaufort Sea coast on the west bank of the Nigliq Channel near the Colville River Delta (CRD). The village is located at 70°13'00" North and 151°00'00" West. The climate is arctic and dominated by extreme temperatures, wind, long daylight hours in the summer and extended periods of darkness during the winter. Temperatures range from -56 to 78°F with the daily minimum temperature below freezing 297 days per year. Annual precipitation is minimal and

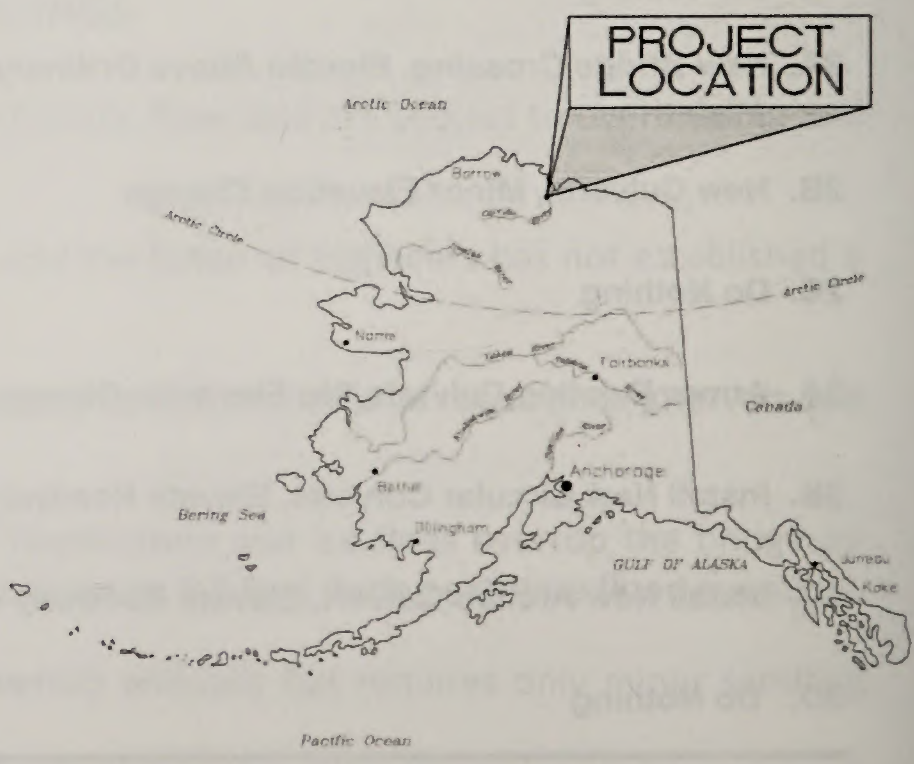



Figure 1: Project Location Map

averages around 5 inches with an annual snowfall of 20 inches.

This study evaluates three crossings - two culvert crossings and one failed bridge crossing located on an unnamed drainage channel. See **Figure 2.**

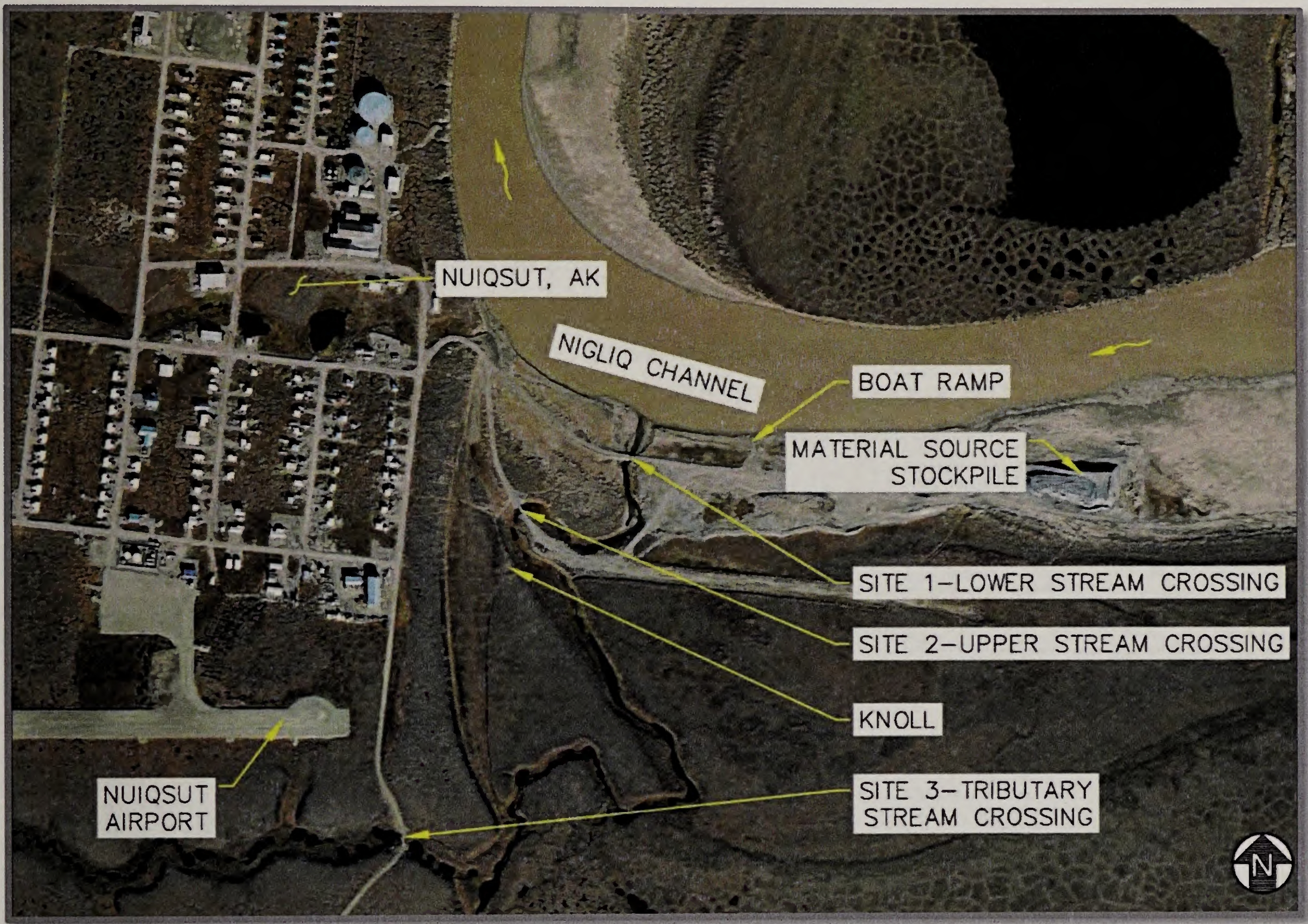



**Figure 2: Site Location Map**

The Lower Stream Crossing (Site 1) is a temporary culvert crossing approximately 300 feet from the Nigliq Channel. Currently, it provides the only access to the City's boat ramp and material source stockpile. This crossing requires complete reconstruction after the high water and ice jamming events every spring. The Upper Stream Crossing (Site 2) is a bridge constructed in 1974 approximately 1,550 feet upstream from Nigliq Channel.

This crossing originally provided access to the village boat ramp and material source stockpile, but has not been operational for the past couple of years. The lower stream crossing was established upon failure of this structure.

The Tributary Stream Crossing (Site 3) is a culvert crossing approximately 6,200 feet upstream from the Nigliq Channel that provides the only access to the community's water source.

## 1.4 Background

The Colville River is the largest river basin north of the Brooks Range draining nearly 23,500 square miles. (Baker, 2013 Colville River Delta Spring Breakup Monitoring & Hydrologic Assessment). Spring breakup on the Colville River is dominated by ice jams, glaciering, large ice floes, and high flow rates for an approximate 3 week period each spring. The three crossings are located on an unnamed stream channel adjacent to the Nigliq Channel. See **Figure 2.** The crossings are located in the flood plain of the Colville River.

ConocoPhillips has studied the timing and breakup of the CRD flooding since 2002, including the Nigliq Channel. ConocoPhillips has four stream monitoring stations (MON20, MON22, MON23 and MON28), on the Nigliq Channel downstream of Nuiqsut. Approximately 1.5 miles downstream from Nuiqsut the Nigliq Channel branches into another minor side channel, the Nigliagvik Channel. Peak discharge and water surface elevation in the Nigliq Channel has been monitored at the ice road crossing to CD5 between MON20 and MON23 since 2009. Peak annual discharges and water surface elevations (WSE) are shown in **Table 1**. The WSE is based on the British Petroleum Mean Sea Level (BPMSL) vertical datum. The scope of this study excluded any surveying, ties, or extrapolation to the BPMSL vertical datum.

**Table 1: Nigliq Channel Historical Summary of Peak WSE CD5 Road**

| Year | Peak Indirect Discharge (cfs) | Peak WSE (ft BPMSL) |
|---|---|---|
| 2014 | 66,000 | 9.38 |
| 2013 | 110000 | 12.42 |
| 2012 | 94,000 | 8.82 |
| 2011 | 141,000 | 9.89 |
| 2010 | 134,000 | 9.65 |
| 2009 | 57,000 | 7.91 |

Source Baker, 2013 CRD Spring Breakup Monitoring and Hydrologic Assessment

## 1.5 Crossing Evaluation

### 1.5.1 Lower Stream Crossing (Site 1)

The Lower Stream Crossing at Site 1 is a culvert crossing constructed after the upstream bridge failed. See **Figure 3**. The road was rerouted and culverts were installed approximately 1,250 feet downstream from the bridge to provide access to the boat ramp and village material source stockpile. The temporary culvert crossing is two 48-inch corrugated metal pipes (CMP) 42-feet in length. These pipes sit atop another series of five to seven buried steel pipes that are estimated to range in sizes from 18-inch to 24-inch. A 16-foot wide gravel roadway crosses the

existing 48-inch diameter culverts. Due to the proximity of the lower stream crossing to the Nigliq Channel (approximately 300-feet) it is subjected to major damage during the spring breakup events and often times has to be reconstructed when the water levels recede.

Currently, it provides the only access to the community boat ramp and material source stockpile. This low profile road is approximately three feet above the surrounding terrain. This crossing is reported to fail almost every spring from overtopping, high flows and ice floes which erode the gravel embankment and scours around the culverts.

**Figure 3: Site 1 Culverts**

### 1.5.2 Upper Stream Crossing (Site 2)

The Upper Stream Crossing at Site 2 is a steel bridge constructed in 1974. This crossing originally provided the access to the old airport in the 1970s and then the village boat ramp and material source stockpile until its failure a few years ago. The bridge is a steel girder bridge supported by steel H-piles with abutments retained by timber lagging between piles. The bridge span length is 42 feet, measured from end of girder to end of girder. The bridge has a 14-foot wide overall deck width and decking consists of 2 x 8-inch treated timbers bolted together and attached to the steel girders. Railing consists of 12 x 12-inch timber posts and galvanized guardrail.

**Figure 4: Failed Bridge at Site 2**

The decking, girders and guardrail have failed. See **Figure 4**. Physical evidence from debris lines indicate that the Colville River spring flood waters overtop the bridge and the bridge elements have failed from the hydraulic pressures and/or impacts from ice floes. The steel pile and timber abutments have survived 40 years with only minor damage and displacement. See **Figure 5**. Steel elements show heavy surficial rust.

Figure 5: Bridge Abutments at Site 2

### 1.5.3 Tributary Stream Crossing (Site 3)

The Tributary Stream Crossing at Site 3 is a culvert crossing that provides access to the community's water supply - a fresh water lake located 1.2 miles south of the village. The 16-foot wide gravel roadway crosses the unnamed drainage that is estimated to be approximately 250 feet wide and 15 feet deep. The road profile sags approximately 11 feet at the culverts. Culverts were reportedly installed after a previous bridge failed.

The crossing consists of three 48-inch diameter by 40-foot long galvanized corrugated steel culverts. See **Figures 6 and 7**. Physical evidence of a debris line and anecdotal information indicate the roadway overtops yearly at spring breakup. To help protect the structure, the Borough has armored the inlets and outlets with sandbags. According to the Public Works Supervisor for Nuiqsut, the addition of sandbags has greatly extended the life of the structure. The condition of the sandbags is fair. The sandbags are easily accessible to vandalism. This crossing requires minimal maintenance and reconstruction after spring breakup, according to local public works staff.

The crossing appears to be in the floodplain of the Colville River, but primarily drains snowmelt in a basin defined later in this report south and west of Nuiqsut. The overtopping is likely caused by high spring breakup flows and undersized culverts.

**Figure 6: Site 3 Crossing Looking South**

**Figure 7: Site 3 Culverts - Downstream Face**

## 1.6 Flood and Stage Frequency

Since all of the crossings are located within the Colville River floodplain, flood and stage frequency depend heavily on Colville River hydrology. From 1992 to 2014, the measured peak flow ranged from 159,000 – 590,000 cfs, with an average peak discharge of 294,000 cfs. The peak stage varied between 12.20 – 20.69 feet (BPMSL), with an average historical peak of 16.79 feet (BPMSL). The earliest seasonal occurrence of peak flow was May 16, and the latest was June 11.

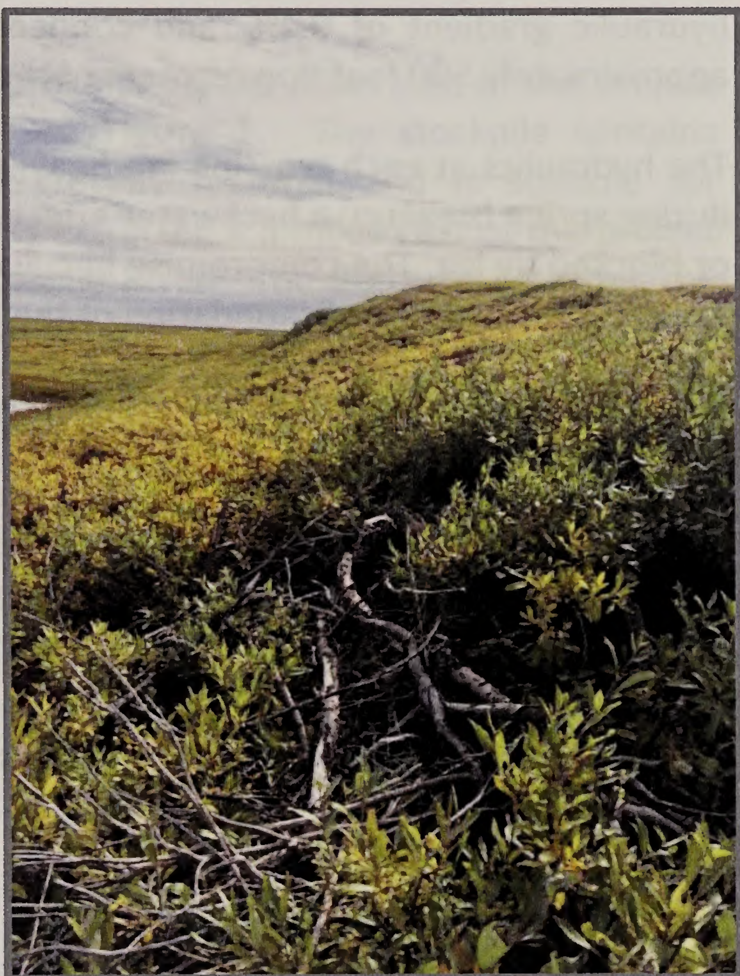


**Figure 8: Upper Stream Crossing (Site 2), High Water Debris Line**

Colville River data collected for ConocoPhillips has limited applicability to Nuiqsut. Water surface elevations refer to a proprietary vertical datum, BPMSL, which prevented calibration of elevation data collected by HDL and others. Additionally the ConocoPhillips studies did not include a monitoring station immediately in the vicinity of Nuiqsut. Thus, there is no record of peak flow stage and discharge that accounts for isolated seasonal flow events caused by ice jams in the Nigliq Channel at Nuiqsut.

For the crossings in this report, peak flood stage was determined by examining surrounding terrain for evidence of past high water events, such as woody debris deposited at a consistent elevation. See **Figure 8**. We found two locations with evidence of debris from high water events. We estimated that the lower of the two debris lines represented a normal high water event due to the large amount of debris in the area. The relative elevation of this debris line was approximately 2-feet higher than the centerline of the bridge deck. We estimated the higher of the debris lines represented an extreme high water event. This debris line was measured to be approximately 8.5-feet higher than the bridge deck.

For the comparison of alternatives, peak discharges, calculated by USGS regression equations, were used to estimate the preliminary bridge and culvert sizes. Determination of actual peak stage and discharge for design should include installation of stream gages at each of the crossings in question and the conduction of a flood study.

## 1.7 Drainage and Hydraulics

Sites 1 and 2 are located on an unnamed stream that meanders north from the drinking water supply to its outfall at the Nigliq channel. The drainage area upstream of the crossings is approximately 24.5 square miles. The hydraulic gradient of the channel is extremely mild at

approximately 0.07%. The upstream watershed consists of flat, sparsely vegetated tundra with many permafrost lakes and ponds.

Site 3 drains an area of 9.5 square miles, and conveys snowmelt and permafrost thaw that collects in a series of kettle ponds south of the Nuiqsut airport runway. The tributary has a mild hydraulic gradient of 0.4%, and connects with the main channel of the unnamed stream approximately 500 feet downstream of the road crossing.

The hydraulics at each crossing are heavily influenced by the Colville River. As the Colville rises during spring breakup, a backwater effect can be created as culvert outlets become submerged or blocked by ice. The compromise in culvert capacity causes a rise in the headwater elevation, and in some cases, total inundation of the roadway.

Culvert design criteria should comply with the Alaska Highway Drainage Manual, Alaska DOT&PF, June 13, 2006.

Bridge hydraulic design criteria are provided in Sections 10.2 and 10.3 of the Alaska Highway Drainage Manual. The primary design constraint is maintaining a minimum of 3 feet of vertical clearance for passage of ice and debris at the design flow.

### 1.8 Soil Conditions

The project area is located in the Arctic Coastal Plain. The coastal plain is typically poorly drained and consequently marshy in the summer. Permafrost is known to exist from 800 - 1,000 feet below the ground surface. Soil conditions are unknown at these sites, but are generally assumed to be ice-rich, fine-grained soils with a thawed active layer of 1 to 3 feet in virgin undisturbed tundra, 6 to 10 feet in gravelly material, and deeper in the vicinity of stream channels where thaw bulbs are known to exist.

A geotechnical evaluation has not been performed as part of this contract, but should be performed prior to design and construction. A full geotechnical investigation should be conducted including a subsurface boring program to the depth of expected foundations with subsurface temperature measurements and laboratory testing. At a minimum, one boring should be performed per substructure and one boring per 50 linear feet of wingwall. Borings should include Standard Penetration Testing (SPT) in unfrozen soils and macro-coring, or equivalent sampling in frozen soils to retrieve samples of the frozen soil and ice. The subsurface temperature should be measured using thermistors to a depth of 10 feet below expected foundations. Laboratory testing should include grain size distribution analyses, moisture content, Atterberg limits (if applicable), and salinities. A grain size distribution analysis and proctor test should be performed on the anticipated fill material. In addition, samples of the stream bed materials should be collected to support evaluation of the scour potential.

## 1.9 Material Source

Gravel and riprap are the two main aggregate materials needed for the project.

### 1.9.1 Gravel

The Borough's material source stockpile is located approximately 0.5 miles east of the project areas on the south bank of the Nigliq Channel. See **Figure 2**. The stockpile contains approximately 150,000 cubic yards (CY) of sandy gravelly material and is suitable for constructing roadway embankments. The material was extracted 4.5 miles east of the project area on the east bank of the main channel of the Colville River. The Borough indicates the material was delivered to the stockpile in the winter of 2014/2015 for $40 per CY; 70,000 CY of this material is dedicated to the Colville River Access Road project. We understand the remaining 80,000 CY is available for Borough public works needs.

### 1.9.2 Riprap

There are no known local sources of rock for riprap. Most armor stone on the North Slope comes from Cape Nome or Dutch Harbor via ocean barge. The nearest upland source is Atigun Pass. Atigun Pass riprap would be mined and transported to Prudhoe Bay via the Dalton Highway and then to Nuiqsut via ice roads. The cost is estimated to be about $375 per CY in place - which is less than barged riprap.

## 1.10 Roadway Design Criteria

Roadway design Criteria are set forth in **Table 2**.

**Table 2: Roadway Design Criteria**

| ELEMENT | VALUE | SOURCE |
|---|---|---|
| Construction Classification | Improvement of Existing Road | |
| Design Functional Classification | Very Low-Volume Local Road / Rural Minor Access Road | AASHTO GDVLVLR 2001 |
| Design Year | 2036 | |
| AADT Construction Year (2016) | <400 | |
| Mid-Design Year (2025) | <400 | |
| Design Year (2035) | <400 | |
| Design Hourly Volume (DHV) | <400 | |
| Directional Split (%D) | 50/50 | |
| (%T) | 50% | |
| Equiv. Single Axle Load (ESAL) | N/A | |
| Pavement Design Year | N/A | |

| | | |
|---|---|---|
| Design Vehicle | N/A | |
| Design Speed (Terrain) | 25 mph (Level) | |
| Stopping Sight Distance | 250 (Assumed "Higher Risk" & doubled per p.52 | AASHTO GDVLVLR 2001, p. 52 & Ex. 8, p.34 |
| Maximum Allowable Grade<br>Minimum Allowable Grade | 7%<br>0.5% | AASHTO PGDHS 2011, Tbl. 5.2, pg. 5-3 |
| Minimum Radius of Curvature | 210 ft with Tc=0.4 (wet earth) | AASHTO GDVLVLR 2001, p. 51 |
| Minimum K-Value for Vertical Curves | Crest = 29<br>Sag = 26 | AASHTO GDVLVLR 2001, Ex. 12, pg. 39<br>AASHTO PGDHS 2011, Tbl. 5.3, pg. 5-4 |
| Number of Roadways | 1 lane | |
| Width of Traveled Way | 16 ft | |
| Width of Shoulder | N/A | |
| Surface Treatment | N/A | |
| Side Slope Ratios | Fore: 2H:1V<br>Back: 2H:1V | |
| Degree of Access Control | N/A | |
| Median Treatment | N/A | |
| Illumination: | N/A | |
| Curb Usage and Type | N/A | |
| Bicycle/ Pedestrian Provisions | N/A | |

## 1.11 Design Standards and Guidelines

Design standards should comply with the following publications:

- Guidelines for Geometric Design of Very Low-Volume Local Roads (ADT ≤ 400), American Association of State Highway and Transportation Officials (AASHTO), 2001.
- A Policy on Geometric Design of Highways and Streets (PGDHS or "Green Book"), AASHTO, 2001.
- Bridge LRFD Design Specifications, AASHTO, 2014.
- Alaska Highway Drainage Manual, Alaska Department of Transportation and Public Facilities (ADOT&PF).

## 2.0 ALTERNATIVES

The following feasible alternatives are considered.

Site 1

- Alternative 1A - Remove Crossing and Salvage Useable Materials
- Alternative 1B - Do Nothing

Site 2

- Alternative 2A - New Bridge Crossing, Elevate Above Ordinary High Water
- Alternative 2B - New Culverts, Minor Elevation Change
- Alternative 2C - Do Nothing

Site 3

- Alternative 3A - Armor Existing Culverts, No Elevation Change
- Alternative 3B - Install New Circular Culverts, Elevate Roadway 3 Feet
- Alternative 3C - Install New Arched Culvert, Elevate Roadway 4.5 Feet
- Alternative 3D - Do Nothing

### 2.1 Alternative 1A – Remove Crossing and Salvage Useable Materials

Alternative 1A consists of removing the lower stream crossing at Site 1 and salvaging the aggregate and two 48-inch culverts. The crossing is within 300 feet of the Nigliq Channel and is mostly affected by high flows in the Nigliq Channel. The crossing is reconstructed every spring. The banks of the stream and streambed would be reshaped and blended to match the existing contours to help facilitate the flow. Removing this crossing would eliminate a maintenance/reconstruction project every spring. Removing the crossing at Site 1 cannot occur until the crossing at Site 2 is reconstructed.

### 2.2 Alternative 1B - Do Nothing

Alternative 1B is to leave the lower stream crossing at Site 1 in place. If Alternative 1B is selected, the crossing will likely blow out within one year making the road to the boat ramp and material source stockpile impassible.

### 2.3 Alternative 2A – New Bridge Crossing, Elevate Above Ordinary High Water

This alternative consists of a one lane modular bridge on a steel pile foundation. The proposed superstructure would be a prefabricated modular bridge with an estimated deadload of 34-kips. The bridge would be designed to withstand loading conditions consistent with AASHTO's HL-93 loading condition, which is defined as lane load plus design truck load. In accordance with the Guidelines for Geometric Design of Very Low-Volume Local Roads (ADT ≤ 400) the recommended bridge width is 15 feet. This bridge would be constructed at the previous location and the span would remain unchanged at 42 feet. Prior to any new construction, the existing bridge would be removed and all salvageable materials delivered to the city landfill. The existing piles would be pulled using a vibratory hammer, and new piles driven at the same approximate location.

To allow passage of debris, the bottom chord of the new modular bridge would be elevated to a height of 3-feet above the ordinary high water mark per the recommendation of the Alaska Highway Drainage Manual. The deck height of the new bridge is estimated to be about 8 feet above that of the previous bridge. Based on the debris lines observed in the field, the additional height of this bridge would keep the structure from being impacted during ordinary high water events and spring ice jams, but not extreme flooding. Elevating the new structure would require reconstruction of the approaches.

According to the Alaska Highway Preconstruction Manual, bridge railings must comply with NCHRP 350 test level 2 or 3. To increase bridge rail performance the test level 3 railing should be considered.

Per the AASHTO Guidelines for Geometric Design of Very Low-Volume Local Roads (ADT ≤ 400) the use of guardrails or other traffic barriers are not recommended and deemed impractical for use on roads with very low traffic volumes.

For the purposes of developing a cost estimate, we assumed an active layer of 8 to 10 feet and HP 14 x 117, grade 50, steel H-piles spaced at approximate 6 feet and driven to a depth of 50 feet below the ground surface. It is anticipated that the piles would be driven in the same general location as the existing piling. In permafrost, piles will likely require predrilling.

With an anticipated embankment height of 18 feet, abutments would consist of the H-piles, 8-inch x 8-inch treated timber lagging and horizontal steel rod tiebacks and deadmen to restrain lateral earth pressures. A steel pile cap would support the modular bridge and should be designed to resist the force of ice jams should the ordinary high water mark be exceeded. Riprap armoring would be installed on approach slopes and along the abutment toe to resist erosion and scour. See the concept drawings in **Appendix B**.

This alternative would elevate the bridge above the estimated ordinary high water mark, but could be expected to overtop occasionally and be damaged by extreme flood events on the Colville River. Approach slope armor may be displaced by large ice floes and would require maintenance. Stream gaging and flood study would be needed to estimate the recurrence

interval and flood stages for a proper bridge design at Site 2. The roadway from the boat ramp to the village would intentionally not be elevated to allow flood waters and ice floes to pass around the bridge and approaches and avoid having the roadway act as a dam.

## 2.4 Alternative 2B – New Culverts, Minor Elevation Change

Alternative 2B consists of installing three 120-inch diameter galvanized steel culverts. Sheet piling should be considered under culverts at both ends to prevent piping around the bottom of culverts. Rigid insulation would be installed under culverts to avoid thaw settlements. Prior to any new construction, the existing bridge would be removed and all materials disposed of at the landfill. Existing piles would be pulled or cut off below grade.

A preliminary hydraulic analysis was performed to compare the existing condition to three 10-foot diameter culverts with headwalls. HEC-RAS modeling software was used to develop hydraulic models based on elevations recorded during the site visit. The complexity of the hydraulic processes associated with the ice jams in the Colville River Drainage limits the ability to validate the modeling, but it allows for a general comparison between the existing structure and a proposed structure.

Based on the Alaska Department of Transportation's listed design value for bridges in flood hazard areas, the 100-year peak flow was selected as the design flow. This flow was calculated using USGS regression equations. The model assumed that the bridges or culverts would have a 2-foot blockage due to icing. The results are depicted in **Table 3**.

**Table 3: Upper Stream Crossing Model Results**

| | Existing Bridge | Proposed Condition<br>3 – 120" Culverts |
|---|---|---|
| $Q_{10}$ Backwater Elevation (feet below low chord or top of pipe) | -1.3 | +1.1 |
| Flow Capacity | 700 cfs | 1,350 cfs |

The results suggest that installing three 120-inch culverts would increase freeboard by 2.4 feet and nearly double the flow capacity.

This Alternative assumes there is no benefit to elevating the crossing because the roadways have flooded. Finished grade over the culverts would approximately match that of the existing bridge approaches with 2 feet of minimum cover over new culverts.

To prevent piping under the culverts, a sheet pile wall would be installed at the inlet and outlet ends to prevent piping under the culvert bottoms. The culverts would be bolted to a steel

angle which is in turn secured to the sheet piling. The sheet piling wall shall be cut to accommodate the bottom of the culvert and driven to refusal at the permafrost interface.

The crossing would be armored with 32-inches of Class II riprap from the toe of the slope to the shoulder of the road. This armor toes should be keyed in at the bottoms and ends to prevent edge scour. A riprap apron should extend 15-feet in front of the inlet and outlet ends of the culverts.

Approach slope armor may be displaced by large ice floes and would require some maintenance but less than an elevated bridge. Stream gaging and flood study would be needed to estimate the flood recurrence intervals and stages for design. The roadways and crossings would flood more frequently than the Alternative 2A, the elevated bridge.

## 2.5 Alternative 2C – Do Nothing

Currently, half of the bridge decking is missing and a wooden barricade with a single warning sign is the only safety measure implemented. Leaving the site as-is is a potential hazard and liability for the Borough and therefore this alternative is not recommended. The bridge and abutments should be removed and the slopes graded to match the existing contours.

## 2.6 Alternative 3A – Armor Existing Structure, No Elevation Change

During HDL's site visit in August 2015, it was observed that very little flow was active through the culverts at Site 3. However, a high water debris line was discovered upstream of the crossing. This upstream debris line was measured at approximately 4.5 feet above the crest of the road at the culverts. Downstream of the crossing, a high water debris line was observed approximately 2 feet below the top of the road. Based on the debris lines, there appears to be a significant backwater buildup during peak flows resulting in roadway overtopping and erosion damage. This effect can be mitigated through hydraulic improvements at the crossing. This alternative, however, makes no improvement to the crossing's hydraulic issues but includes armoring the existing culverts and installing a minimum of 32 inches of Class II riprap. The embankment slopes would be armored and culvert ends armored 15 feet in front of the culvert ends to a width 4 feet on either side of the outside of the culvert. This alternative does not mitigate the backwater buildup during peak flows, but addresses erosion and damage sustained during these periods. Once the waters have receded there may still be a need for minor maintenance.

This alternative would be prone to flooding during breakup and would not provide all season access to the water source lake. This alternative is not recommended if all season access to the water source lake is required.

## 2.7 Alternative 3B – Install New Circular Culverts, Elevate Roadway 3 Feet

Alternative 3B consists of installing three 72-inch circular culverts at Site 3, raising road grade approximately 3 feet, and armoring slopes and aprons similar to Alternative 2B. Rigid insulation would be installed under culverts to reduce thaw settlements. To prevent piping under the culvert bottoms, a sheet pile wall would be installed at the inlet and outlet ends of the culverts. The culverts shall be bolted to an angle and secured to the sheet piling. The sheet piling would be trimmed to accommodate the shape of the culvert. Slopes and inlet and outlet aprons would be armored with 32-inches of Class II riprap. The aprons would extend 15 feet in front of the culverts.

A hydraulic analysis was performed to compare the existing conditions to the recommendation using HY-8 modeling software. It should be noted that the complexity of the hydraulic process associated with ice jams in the Colville River Drainage limits the ability to validate modeling results; however, a performance comparison between the existing and proposed condition is useful.

Based on the Alaska Department of Transportation's design value for low usage secondary highways, the 10-year peak flow was used as the design flow to analyze the tributary stream crossing. The results are depicted in **Table 4** below. USGS regression equations were used to calculate the flow and it was assumed that the culverts would have a 2-foot blockage due to icing.

**Table 4: Tributary Culvert Model Results**

| | Existing Condition 3 – 48" Culverts | Proposed Condition 3 – 72" Culverts |
|---|---|---|
| $Q_{10}$ Backwater Elevation (feet above roadway) | +1.7 | -1.9 |
| Overtopping Flow | 199 cfs | 552 cfs |

The results suggest that upgrading to three 72-inch diameter circular culverts would reduce the backwater elevation by several feet and may significantly reduce the probability of overtopping.

The alternative would provide all season access to the water source lake. This alternative is recommended.

## 2.8 Alternative 3C – Install New Arched Culvert, Elevate Road 4.5 Feet

Alternative 3C consists of installing a single 100-inch by 154-inch arched culvert, rigid insulation, a sheet pile cutoff wall and slope and apron armoring. Similar to Alternatives 3A and 3B, the slopes and aprons would be armored with 32-inches of Class II riprap. The apron would

measure approximately 15-feet by 27-feet in front of culvert inlets and outlets. To achieve the recommended minimum culvert cover of 2 feet, the existing roadway grade would have to be raised by 1.2 feet. In order to mitigate overtopping, similar to Alternative 3B (using the $Q_{10}$ backwater information) the roadway should be raised 4.3 feet. Elevating the roadway would enable the road to be useable during spring breakup.

A preliminary hydraulic analysis was performed similar to Alternatives 3A and 3B. Based on the Alaska DOT's design value for low usage secondary highways, the 10-year peak flow was used as the design flow to analyze the tributary stream crossing. The results are depicted in **Table 5** below. USGS regression equations were used to calculate the flow and it was assumed that the culverts would have a 2-foot blockage due to icing.

**Table 5: Tributary Culvert Model Results**

| | Existing Condition 3 – 48" Culverts | Proposed 100" x 154" Arched Culvert |
|---|---|---|
| $Q_{10}$ Backwater Elevation (feet above roadway) | +1.7 | -0.6 |
| Overtopping Flow | 199 cfs | 557 cfs |

The results suggest upgrading to a single 100-inch by 154-inch arched culvert would reduce the backwater elevation by a couple of feet and would reduce the occurrence of overtopping.

This alternative may be feasible, but its design should take special precautions to insulate the foundation under the arched culvert to prevent frost jacking. Arched culverts are susceptible to failure from frost jacking because of their flat bottom. Recently, a similar multiplate arched culvert in Buckland failed when the bottom jacked, while a circular multiplate structure alongside it performed satisfactorily. It is reported that an ice lense formed underneath, causing the bottom to buckle. For this reason, additional insulation should be added to prevent ice lenses from forming under the arch.

## 2.9 Alternative 3D – Do Nothing

Alternative 3D leaves the existing crossing as is. With minor spring time repairs this crossing may be useable for years, but will eventually fail due to damage sustained during high water events and ice jamming activities. If the Borough desires all season access to the water source lake, this option is not recommended.

### 2.10 Other Alternatives Considered

Other alternatives were considered, but deemed not feasible for technical or economic reasons.

#### 2.10.1 Elevate Bridge at Site 2 Above Extreme High Water

Elevating the bridge at Site 2 above the extreme high water event was considered, but deemed not practical or feasible. This alternative would require extremely high, roughly 24.5–foot, abutment walls and extended approaches. Building abutments and approaches of this magnitude would require massive amounts of fill material and gravel, which would be expensive and complicated. Elevating the bridge to this extreme would pose no benefit to the community as the surrounding access roads would be inundated and the bridge would not be of any benefit to the general public. For cost estimate breakdown see **Page 10 of Appendix A.**

#### 2.10.2 Precast Concrete Girders

A bulb-T prestressed concrete bridge was considered for Site 2, but deemed not economically feasible due to the short span. According to a local prestressed concrete manufacturer, a short 50-foot span with a 14 to 16 foot deck width, three 42-inch bulb-T prestressed concrete girders would not be competitive with modular steel bridges of an equivalent size. The concrete would also be more susceptible to ice damage because of the girder depth, and the bulbs lesser lateral strength when compared to a steel bridge.

#### 2.10.3 Elevate the Entire Road to the Boat Ramp Above Extreme High Water

Elevating and armoring the 3200 feet of road to the boat ramp and bridge at Site 2 above extreme high water was considered, but the high cost, estimated to be \$20M to \$30M for the 28,800 CY of riprap and 92,800 CY of gravel fill was deemed not economically feasible. Elevating the entire road and bridge would hydraulically act as a dam for Colville River flood waters and would be prone to flood damage. The high cost compared to the benefit of providing access to the boat ramp and material source during flood events makes this concept not feasible.

## 3.0 CONSTRUCTION METHODS

The nature of the work and soils in the area lend itself to construction during multiple seasons. The mobilization/demobilization of materials and equipment on the ice road coupled with winter and summer construction activities will extend construction over the course of one year.

Construction access at Site 3 is governed by the need for access to the village's water source. The 3rd or 4th week of June the city begins pumping water from the lake and pumps continuously until the tanks are full, which is typically around the 1st week of September. The shutdown date varies according to weather. Freezing of the waterline ends the pumping season. During the pumping season, the water system operators require unrestricted access to service pumps and monitor the operation.

## 3.1 Construction Methods for Culverts

### 3.1.1 Site 2

The existing bridge should be removed and all salvageable materials shall be delivered to the Borough. The existing piles may be able to be pulled, salvaged, and returned to the City; otherwise, the piling should be cut two feet below grade. In late fall, the sheet pile walls should be installed when the active layer is at its maximum depth. These walls are to be driven through the active layer and to refusal in the permafrost layer below. The sheet pile walls should be left high, about to the spring line of the culverts. Under frozen ground conditions, the Contractor would excavate and install a layer of rigid insulation and install approximately 4-feet of sacrificial fill material to protect the crossing during spring runoff and breakup. After breakup, culverts would be installed and remaining thawed fill placed and compacted under low flow conditions. The sheet piles would be trimmed and attached to culverts using a double rolled angle. Fill slopes should be armored with Class II riprap 32-inches deep over a geotextile fabric with keyed edges. The culvert inlets would be armored with a riprap apron.

### 3.1.2 Site 3

Due to the average historical high water date of the Colville River on May 31st, and the need for access to the water source lake by the 3rd week in June, winter construction methods will need to be employed. In late fall, the existing culverts and fill would be removed and sheet pile walls installed similar to Site 2. Sheet piles would be cut to an elevation about 6 inches above the invert of the inlet and outlet of the culverts. Then under frozen ground conditions, excavation would occur to the bottom of insulation, insulation installed, then fill brought back up to the bedding depth of the culvert inverts. The culverts, fill, geotextile, and riprap could be placed under frozen ground conditions, if dry granular material could be properly placed and compacted; or the contractor could place temporary riprap to protect during breakup and complete the project under thawed conditions. The sheet piles would be trimmed and attached to culverts using a double rolled angle. Fill slopes should be armored with Class II riprap 32-inches deep over a geotextile fabric with keyed edges. The culvert inlets would be armored with a riprap apron.

### 3.2 Construction Methods for the Bridge

The removal of the existing bridge structure is needed to construct the bridge. The existing bridge should be removed and all salvageable materials shall be delivered to the Borough. The existing piles should be pulled, salvaged, and returned to the City, or the bridge offset to miss existing piles.

Gravel approaches would be removed to the extent required to drive piles and construct deadmen anchors. New H-piles would be predrilled with an undersized pilot hole and driven to depth. Near-water work should be avoided until spring breakup high flows have receded.

The abutments and wing walls, consisting of piles, treated-timber lagging and deadman anchors, would be constructed during thawing conditions to help ensure proper placement and compaction of fills. The pile caps, elastomeric bearing pads, backwall, bridge structure, and appurtenances would be installed when environmental conditions allow for proper welding and connection installation.

## 4.0 MAINTENANCE AND OPERATION

Yearly maintenance may be required at Sites 2 and 3 to ensure the longevity of the crossings. Erosion control and bank stabilization will need to be maintained and repaired in a timely manner to protect the structures in place. These structures will be subject to flooding and overtopping during extreme events and will need to be repaired and rearmored, if needed. If normal maintenance is not conducted in a timely fashion the structures may prematurely fail.

It is recommended to inspect culverts on an annual basis and after extreme events. The National Bridge Inspection Standards (NBIS) recommends that bridges should be inspected every two years and that the maximum interval between inspections should not exceed four years.

## 5.0 ENVIRONMENTAL CONSIDERATIONS AND PERMITTING REQUIREMENTS

HDL conducted preliminary environmental research using the most current available data from state and federal agencies to identify environmental resources in the vicinity of the proposed project. The purpose of the preliminary research was to assist in identifying permitting and regulatory requirements to ensure environmental considerations are adequately addressed in developing any of the "action" alternatives for the proposed project. Environmental categories with resources potentially present in the project area are discussed below.

**National Environmental Policy Act (NEPA) Review**

The funding source for the proposed project will dictate the type of environmental documentation necessary to satisfy state and federal requirements and/or authorizations.

Should federal funds be used, the federal agency appropriating the funds would likely assume the role of lead federal agency and would be responsible for development of appropriate NEPA documentation. NEPA documentation would outline potential impacts to the natural and man-made environment.

Should the project be entirely state funded, the NSB's primary environmental documentation will be the environmental review conducted for this PAR, which identifies potential environmental impacts and outlines permits and authorizations needed for the project. A NSB or state-funded project triggers the NEPA process when a federal permit is required, such as a U.S. Army Corps of Engineers (USACE) Section 404 permit for impacts to wetlands. This environmental review may be used by the USACE to streamline their NEPA documentation efforts and potentially decrease the amount of time necessary in receiving authorization.

**Wetlands & Waters of the U.S.**

A review of the U.S. Fish & Wildlife Service (USFWS) National Wetlands Inventory and recent satellite imagery indicates the project area contains wetlands under USACE jurisdiction. It is anticipated that the project will impact wetlands, and will require authorization under a Nationwide Permit and submittal of a Pre-Construction Notification to USACE. Should the project disturb more than 0.50 acre of wetlands, an Individual Permit application would be required.

Construction of the proposed project will involve the discharge of construction storm water into waters of the U.S. Should the project involve more than one acre of disturbed ground, coverage under the Alaska Department of Environmental Conservation's Alaska Pollutant Discharge Elimination Systems (APDES) Construction General Permit for stormwater discharges would be required.

**Cultural, Historic, Pre-Historic, & Archaeological Resources**

The likelihood of disturbing previously unknown cultural, historic, pre-historic, or archaeological resources within the project areas is low since the areas have been previously disturbed by construction of existing infrastructure. The project will require a Certificate of Traditional Land Use Inventory (TLUI) Clearance from the NSB Department of Inupiat History, Language, and Culture (IHLC).

Should the project receive state or federal funding, consultation with the Alaska Office of History and Archaeology under the Alaska Historic Preservation Act, or State Historic Preservation Officer (SHPO) under Section 106 of the National Historic Preservation Act, would be required.

## Fish & Wildlife:

**Threatened & Endangered Species**

Initial project scoping conducted using USFWS's Information, Planning, and Conservation System tool indicates there is one species, the polar bear (Ursus maritimus), listed as threatened under the Endangered Species Act (ESA) that is known to inhabit the project area. There are no endangered or candidate species or designated critical habitats located in the project area. Consultation with the USFWS under Section 7 of the ESA would be required if federal funding is received for construction.

**Migratory Birds**

The project is located in areas that have been heavily disturbed; however, shrub and grass-vegetated areas are present. To avoid disturbance to migratory birds, USFWS recommends avoiding clearing from June 1st through August 10th.

**Anadromous Fish Streams**

A review of the Alaska Department of Fish and Game's (ADF&G) Anadromous Waters Catalog (AWC) indicates the project is located on the Nigliq Channel, a tributary of the Colville River, which is listed as supporting several species of anadromous fishes. Consultation with ADF&G during the design phase of the project is recommended to determine whether fish may be present in the project area and if a Fish Habitat Permit will be required.

**Land Ownership**

According the Alaska Division of Community and Regional Affairs' Community Map for Nuiqsut, the project would be located on a combination of lands owned by the Borough, City of Nuiqsut, and Kuukpik Corporation. The project will require easements or rights-of-way prior to construction.

**Environmental Permitting Summary & Recommendations**

**Table 6** below summarizes environmental data and permit requirements for development.

Table 6: Recommended Regulatory and Permitting Tasks

| | |
|---|---|
| **NSB Land Management Regulations (LMR)** | Development Permit. (fee waived for NSB projects). |
| **Wetlands, Waters of the U.S, & Navigable Waters** | Jurisdictional wetlands located within project areas. Section 404 Nationwide Permit/Pre-Construction Notification required. APDES Construction General required if disturbed area is 1 or more acre ($490 fee). |

| | |
|---|---|
| **Cultural, Historic, Pre-Historic, & Archaeological Resources** | Low potential to encounter historic sites; IHLC's Certificate of TLUI Clearance required (fee waived for NSB projects). Consultation with OHA/SHPO required depending on funding source. |
| **Threatened & Endangered Species** | Polar bear listed as Threatened under ESA. Consultation with USFWS required if federally funded. |
| **Migratory Birds** | No vegetation clearing between June 1st and August 10th recommended. |
| **Anadromous Fish Streams** | No AWC-listed anadromous fish habitat in project area; Nigliq Channel of Colville River is approximately 500 feet downstream of Site 1. Consultation with ADF&G recommended during design. |
| **Land Ownership** | Confirm existing or provide easements or rights-of-way for work on NSB, City of Nuiqsut, and Kuukpik Corporation lands. |

## 6.0 ESTIMATE OF PROBABLE COSTS

### 6.1 Capital Cost

Capital costs for the three sites have been prepared based on the analysis provided herein for each of the sites, details of which are provided in **Appendix A** and summarized in **Table 7**. Capital cost estimates are based on the following general assumptions:

1. Work will be competitively bid.
2. Seasonal ice road between Prudhoe Bay and Nuiqsut will be available and constructed by industry.
3. Materials and equipment will mobilize and demobilize via ice road.
4. A site for material staging and equipment storage will be provided at no cost to the contractor.
5. The Borough stockpiled gravel will be available at no cost.
6. Piling will be predrilled in permafrost.
7. Sheet piling will be driven through the thawed active layer to refusal in the permafrost.

8. Construction shall occur during times of low to no flow.
9. Dewatering will be necessary when working at or below the water levels in the surrounding area.
10. Labor assumed to be at Title 36 wage rates.
11. No crushed aggregate surfacing is required for road surfacing.
12. Alternative 1A work will be performed upon completion of Site 2 work by the same Contractor.

**Table 7: Capital Cost Summary**

| Alternative | Capital Cost | Useful Life |
|---|---|---|
| **1A. Remove Crossing and Salvage Useable Materials** | $203,000 | N/A |
| **1B. Do Nothing** | 0 | N/A |
| **2A. New Bridge Crossing, Elevate Above Ordinary High Water** | 3,423,000 | 30 years |
| **2B. New Culverts, Minor Elevation Change** | 3,216,000 | 30 years |
| **2C. Do Nothing** | 406,000 | N/A |
| **3A. Armor Existing Culverts, No Elevation Change** | 1,502,000 | 15 years |
| **3B. Install New Circular Culverts, Elevate Roadway 3 Feet** | 3,352,000 | 30 years |
| **3C. Install New Arched Culvert, Elevate Roadway 4.5 Feet** | 3,932,000 | 30 years |
| **3D. Do Nothing** | 0 | N/A |

## 6.2 Operation and Maintenance Costs

Operation and maintenance (O&M) costs are expected to include minor riprap restoration annually from ice floes; except after extreme flood events which may cause significant damage. O&M costs can be minimized by keeping embankments sloped and low profile to minimize hydraulic impacts and restoration costs.

## 7.0 FINDINGS

1. All three sites are in the flood plain of the Colville River and are subject to overtopping and ice jamming.

2. Little flood information exists for Nuiqsut and the Corps of Engineers has not established a flood datum for Nuiqsut.

3. A flood study and stream monitoring is needed to determine flood recurrence intervals and flood elevations.

4. Debris lines near Site 2 suggest seasonal floodwaters and ice floes overtop the bridge by approximately 2 feet annually and by approximately 8.5 feet during extreme flood events.

5. The Site 3 overtops annually but requires only minor sandbag repair after the high water recedes.

6. Debris lines near Site 3 suggest that the roadway overtops by approximately 4.5 feet during extreme high water events.

## 8.0 RECOMMENDATIONS

1. Conduct a flood study and stream monitoring study to determine flood recurrence intervals and flood elevations.

2. Conduct a geotechnical investigation to determine engineering and thermal properties of soils at the sites to allow for proper design.

3. At the Lower Stream Crossing (Site 1), remove the crossing after the Site 2 crossing is restored: **Alternative 1A – Remove Crossing and Salvage Useable Materials.**

4. At the Upper Stream Crossing (Site 2), remove the existing bridge and install three 120-inch culverts: **Alternative 2B – New Culverts, Minor Elevation Change.**

5. At the Tributary Stream Crossing (Site 3), install three new 72-inch culverts to provide all-season access to the water source lake: **Alternative 3B – Install New Circular Culverts, Elevate Roadway 3 Feet.**

## 9.0 REFERENCES

1. A Policy on Geometric Design of Highways and Streets, (PGDHS or "Green Book") AASHTO, 2011.

2. Alaska Highway Drainage Manual, Alaska DOT&PF. June 13, 2006.

3. Baker. 2013 Colville River Delta Spring Breakup Monitoring & Hydrologic Assessment.

4. Big R Bridge. Standard 4 ¼" Steel Deck 30' to 80' x 14' or 16' Single Lane Bridge – Bridge Detail, December 7, 2015.

5. "Bridges & Structures." Revisions to the National Bridge Inspection Standards (NBIS). N.p., n.d. Web. 07 Dec. 2015.

6. Guidelines for Geometric Design of Very Low-Volume Local Roads (ADT ≤ 400). American Association of State Highway and Transportation Officials (AASHTO), 2001.

7. Green, Ken. NSB CIPM Project Administrator, Personal communication regarding material source stockpile, December 2015.Nukapigak, Thomas. Nuiqsut Public Works Superintendent, Personal Communication, August and November 2015.

8. Roadside Design Guide. AASHTO, 2011.

9. "Village of Nuiqsut | ICAS." ICAS. Web. 16 Sept. 2015.

# APPENDIX A

# COST ESTIMATE

**Nuiqsut Repair Bridge Crossing PAR**
2/10/2016

Alternative 1A - Remove Crossing and Salvage Useable Materials

| ITEM | QUANTITY | DESCRIPTION | UNIT PRICE | TOTAL PRICE |
|---|---|---|---|---|
| 1 | 1 L.S. | Temp Erosion and Pollution Control | 20,000.00 | 20,000 |
| 2 | 1 L.S. | Remove 2-48" CMPs | 25,000.00 | 25,000 |
| 3 | 1 L.S. | Remove 5-7 18"-24" Burried Steel Pipes | 25,000.00 | 25,000 |
| 4 | 1 L.S. | Reshaping and Bank Stabilization | 45,000.00 | 45,000 |
| 5 | 1 L.S. | Salvagable Material | 15,000.00 | 15,000 |
| | | | | |
| | | | | |
| | | | | |

| | | |
|---|---|---|
| Subtotal Construction | | $130,000 |
| Land Acquisition | | 0 |
| City Administration | @ 5% | 6,500 |
| Design | @ 12% | 15,600 |
| Construction Management | @ 15% | 19,500 |
| Project Contingency | @ 15% | 19,500 |
| 3 Years Inflation | @ 3% | 12,100 |
| Subtotal | | $203,200 |

## Nuiqsut Repair Bridge Crossing PAR
2/10/2016

Alternative 1B - Do Nothing

| ITEM | QUANTITY | DESCRIPTION | UNIT PRICE | TOTAL PRICE |
|---|---|---|---|---|
| | | | | |
| | | | | |
| | | | | |
| | | | | |
| | | | | |
| | | | | |
| | | | | |

| | | |
|---|---|---|
| Subtotal Construction | | $0 |
| Land Acquisition | | 0 |
| City Administration | @ 5% | 0 |
| Design | @ 12% | 0 |
| Construction Management | @ 15% | 0 |
| Project Contingency | @ 15% | 0 |
| 1 Years Inflation | @ 3% | 0 |
| Subtotal | | $0 |

## Nuiqsut Repair Bridge Crossing PAR

2/10/2016

Alternative 2A - New Bridge Crossing, Elevate Above Ordinary High Water

| ITEM | QUANTITY | DESCRIPTION | UNIT PRICE | TOTAL PRICE |
|---|---|---|---|---|
| 1 | 1 L.S. | Mobilization/Demobilization | 286,000.00 | 286,000 |
| 2 | 1 L.S. | Temp Erosion and Pollution Control | 75,000.00 | 75,000 |
| 3 | 1 L.S. | Construction Surveying | 90,000.00 | 90,000 |
| 4 | 1 L.S. | Remove Piling, Abutments, and Superstrucure | 75,000.00 | 75,000 |
| 5 | 1 L.S. | Modular Bridge (FOB Seattle) | 54,600.00 | 54,600 |
| 6 | 1 L.S. | Modular Bridge Assembly | 20,000.00 | 20,000 |
| 7 | 17 Tons | Barging of Bridge Structure (SEA to PUD) | 1,000.00 | 17,000 |
| 8 | 332,000 Lbs. | HP14x117 Piling, Grade 50 (2840l.f.) | 1.00 | 332,000 |
| 9 | 20 Days | Install H Piles | 18,000.00 | 360,000 |
| 10 | 9,000 Lbs. | Pile Caps, Backwall, and Bearing Plates | 1.00 | 9,000 |
| 11 | 2,700 B.F. | 8x8 PT Timber | 2.00 | 5,400 |
| 12 | 432 L.F. | Tie Back Anchors | 50.00 | 21,600 |
| 13 | 12 Each | Deadmen | 10,000.00 | 120,000 |
| 14 | 290 C.Y. | Excavation | 50.00 | 14,500 |
| 15 | 3,960 C.Y. | Gravel Fill | 50.00 | 198,000 |
| 16 | 1,500 S.Y. | Geotextile Fabric | 5.00 | 7,500 |
| 17 | 1,000 C.Y. | Rip Rap | 375.00 | 375,000 |
| 18 | 13 Loads | Trucking (Anc. to Nui.) | 10,000.00 | 130,000 |
| | | | | |
| | | | | |
| | | | | |

| | | |
|---|---|---|
| Subtotal Construction | | $2,190,600 |
| Land Acquisition | | 0 |
| City Administration | @ 5% | 109,500 |
| Design | @ 12% | 262,900 |
| Construction Management | @ 15% | 328,600 |
| Project Contingency | @ 15% | 328,600 |
| 3 Years Inflation | @ 3% | 203,100 |
| Subtotal | | $3,423,300 |

**Nuiqsut Repair Bridge Crossing PAR**
2/10/2016

Alternative 2B - New Culverts, Minor Elevation Change

| ITEM | QUANTITY | DESCRIPTION | UNIT PRICE | TOTAL PRICE |
|---|---|---|---|---|
| 1 | 1 L.S. | Mobilization/Demobilization | 268,000.00 | 268,000 |
| 2 | 1 L.S. | Temp Erosion and Pollution Control | 50,000.00 | 50,000 |
| 3 | 1 L.S. | Construction Surveying | 90,000.00 | 90,000 |
| 4 | 1 L.S. | Remove Piling, Abutments, and Superstrucure | 75,000.00 | 75,000 |
| 5 | 195 L.F. | 3 - 120" Φ CMP | 1,800.00 | 351,000 |
| 6 | 6 Each | End Section | 4,000.00 | 24,000 |
| 7 | 55,000 Lbs. | Sheet Piling (1550 S.f.) | 1.00 | 55,000 |
| 8 | 15 Days | Install Sheet Piling | 18,000.00 | 270,000 |
| 9 | 500 Lbs. | 8"x4"x9/16" Rolled Angle H.D.G. | 6.00 | 3,000 |
| 10 | 72 L.F. | Tieback Anchors | 50.00 | 3,600 |
| 11 | 4 Each | Deadmen | 7,500.00 | 30,000 |
| 12 | 19,500 B.F. | 4" Rigid Insulation | 12.00 | 234,000 |
| 13 | 610 C.Y. | Excavation | 50.00 | 30,500 |
| 14 | 1,600 C.Y. | Gravel Fill | 50.00 | 80,000 |
| 15 | 1,030 C.Y. | Riprap | 375.00 | 386,250 |
| 16 | 1,500 S.Y. | Geotextile Fabric | 5.00 | 7,500 |
| 17 | 10 Loads | Trucking (Anc. to Nui.) | 10,000.00 | 100,000 |
| | | | | |
| | | | | |
| | | | | |

| | | |
|---|---|---|
| Subtotal Construction | | $2,057,850 |
| Land Acquisition | | 0 |
| City Administration | @ 5% | 102,900 |
| Design | @ 12% | 246,900 |
| Construction Management | @ 15% | 308,700 |
| Project Contingency | @ 15% | 308,700 |
| 3 Years Inflation | @ 3% | 190,800 |
| Subtotal | | $3,215,850 |

**Nuiqsut Repair Bridge Crossing PAR**

2/10/2016

Alternative 2C - Do Nothing (Remove Bridge)

| ITEM | QUANTITY | DESCRIPTION | UNIT PRICE | TOTAL PRICE |
|---|---|---|---|---|
| 1 | 1 L.S. | Mobilization/Demobilization | 40,000.00 | 40,000 |
| 2 | 1 L.S. | Temp Erosion and Pollution Control | 75,000.00 | 75,000 |
| 3 | 1 L.S. | Remove Piling, Abutments, and Superstrucure | 75,000.00 | 75,000 |
| 4 | 1 L.S. | Reshaping and Bank Stabilization | 50,000.00 | 50,000 |
| | | | | |
| | | | | |
| | | | | |

| | | |
|---|---|---|
| Subtotal Construction | | $240,000 |
| Land Acquisition | | 0 |
| City Administration | @ 5% | 12,000 |
| Design | @ 15% | 36,000 |
| Construction Management | @ 20% | 48,000 |
| Project Contingency | @ 20% | 48,000 |
| 3 Years Inflation | @ 3% | 22,300 |
| Subtotal | | $406,300 |

**Nuiqsut Repair Bridge Crossing PAR**
2/10/2016

Alternative 3A - Armor Existing Culverts, No Elevation Change

| ITEM | QUANTITY | DESCRIPTION | UNIT PRICE | TOTAL PRICE |
|---|---|---|---|---|
| 1 | 1 L.S. | Mobilization/Demobilization | 250,000.00 | 250,000 |
| 2 | 1 L.S. | Temp Erosion and Pollution Control | 50,000.00 | 50,000 |
| 3 | 1 L.S. | Slope Grading | 85,000.00 | 85,000 |
| 4 | 1,425 C.Y. | Riprap | 375.00 | 534,400 |
| 5 | 2,420 S.Y. | Geotextile Fabric | 5.00 | 12,100 |
| | | | | |
| | | | | |
| | | | | |
| | | Subtotal Construction | | $931,500 |
| | | Land Acquisition | | 0 |
| | | City Administration | @ 5% | 46,600 |
| | | Design | @ 12% | 111,800 |
| | | Construction Management | @ 15% | 139,700 |
| | | Project Contingency | @ 20% | 186,300 |
| | | 3 Years Inflation | @ 3% | 86,400 |
| | | Subtotal | | $1,502,300 |

**Nuiqsut Repair Bridge Crossing PAR**
2/10/2016

Alternative 3B - Install New Circular Culverts, Elevate Roadway 3 Feet

| ITEM | QUANTITY | DESCRIPTION | UNIT PRICE | TOTAL PRICE |
|---|---|---|---|---|
| 1 | 1 L.S. | Mobilization/Demobilization | 280,000.00 | 280,000 |
| 2 | 1 L.S. | Temp Erosion and Pollution Control | 50,000.00 | 50,000 |
| 3 | 1 L.S. | Construction Surveying | 90,000.00 | 90,000 |
| 4 | 1 L.S. | Remove Old Culverts | 25,000.00 | 25,000 |
| 5 | 195 L.F. | 72" CMP | 1,200.00 | 234,000 |
| 6 | 6 Each | End Sections | 3,000.00 | 18,000 |
| 7 | 34,000 Lbs. | Sheet Piling (1000 S.f) | 1.00 | 34,000 |
| 8 | 15 Days | Install Sheet Piling | 18,000.00 | 270,000 |
| 9 | 500 Lbs. | 8"x4"x9/16" Rolled Angle H.D.G. | 6.00 | 3,000 |
| 10 | 72 L.F. | Tieback Anchors | 50.00 | 3,600 |
| 11 | 4 Each | Deadmen | 7,500.00 | 30,000 |
| 12 | 12,400 B.F. | 4" Rigid Insulation | 12.00 | 148,800 |
| 13 | 1,280 C.Y. | Excavation | 50.00 | 64,000 |
| 14 | 2,740 C.Y. | Gravel Fill | 50.00 | 137,000 |
| 15 | 1,735 C.Y. | Riprap | 375.00 | 650,625 |
| 16 | 1,390 S.Y. | Geotextile Fabric | 5.00 | 6,950 |
| 17 | 10 Loads | Trucking (Anc. to Nui.) | 10,000.00 | 100,000 |
| | | | | |
| | | | | |
| | | | | |

| | | |
|---|---|---|
| Subtotal Construction | | $2,144,975 |
| Land Acquisition | | 0 |
| City Administration | @ 5% | 107,200 |
| Design | @ 12% | 257,400 |
| Construction Management | @ 15% | 321,700 |
| Project Contingency | @ 15% | 321,700 |
| 3 Years Inflation | @ 3% | 198,900 |
| Subtotal | | $3,351,875 |

**Nuiqsut Repair Bridge Crossing PAR**
2/10/2016

Alternative 3C - Install New Arched Culvert, Elevate Roadway 4.5 Feet

| ITEM | QUANTITY | DESCRIPTION | UNIT PRICE | TOTAL PRICE |
|---|---|---|---|---|
| 1 | 1 L.S. | Mobilization/Demobilization | 328,000.00 | 328,000 |
| 2 | 1 L.S. | Temp Erosion and Pollution Control | 50,000.00 | 50,000 |
| 3 | 1 L.S. | Construction Surveying | 90,000.00 | 90,000 |
| 4 | 1 L.S. | Remove Old Culverts | 25,000.00 | 25,000 |
| 5 | 72 L.F. | 100-inch x 154-inch Pipe Arch Culvert | 1,800.00 | 129,600 |
| 6 | 2 Each | End Sections | 4,000.00 | 8,000 |
| 7 | 40,000 Lbs. | Sheet Piling (1130 S.F.) | 1.00 | 40,000 |
| 8 | 15 Days | Install Sheet Piling | 18,000.00 | 270,000 |
| 9 | 1,000 Lbs. | 8"x4"x9/16" Rolled Angle H.D.G. | 3.00 | 3,000 |
| 10 | 72 L.F. | Tieback Anchors | 50.00 | 3,600 |
| 11 | 4 Each | Deadmen | 7,500.00 | 30,000 |
| 12 | 30,800 B.F. | 4" Rigid Insulation | 12.00 | 369,600 |
| 13 | 1,500 C.Y. | Excavation | 50.00 | 75,000 |
| 14 | 3,300 C.Y. | Gravel Fill | 50.00 | 165,000 |
| 15 | 2,190 C.Y. | Riprap | 375.00 | 821,250 |
| 16 | 1,660 S.Y. | Geotextile Fabric | 5.00 | 8,300 |
| 17 | 10 Loads | Trucking (Anc. to Nui.) | 10,000.00 | 100,000 |
| | | | | |
| | | | | |
| | | | | |

| | | |
|---|---|---|
| Subtotal Construction | | $2,516,350 |
| Land Acquisition | | 0 |
| City Administration | @ 5% | 125,800 |
| Design | @ 12% | 302,000 |
| Construction Management | @ 15% | 377,500 |
| Project Contingency | @ 15% | 377,500 |
| 3 Years Inflation | @ 3% | 233,300 |
| Subtotal | | $3,932,450 |

**Nuiqsut Repair Bridge Crossing PAR**
2/10/2016

Alternative 3D - Do Nothing

| ITEM | QUANTITY | DESCRIPTION | UNIT PRICE | TOTAL PRICE |
|---|---|---|---|---|
| | | | | |
| | | | | |
| | | | | |
| | | | | |
| | | | | |
| | | | | |

| | | |
|---|---|---|
| Subtotal Construction | | $0 |
| Land Acquisition | | 0 |
| City Administration | @ 5% | 0 |
| Design | @ 12% | 0 |
| Construction Management | @ 15% | 0 |
| Project Contingency | @ 15% | 0 |
| 1 Years Inflation | @ 3% | 0 |
| Subtotal | | $0 |

**Nuiqsut Repair Bridge Crossing PAR**
2/10/2016

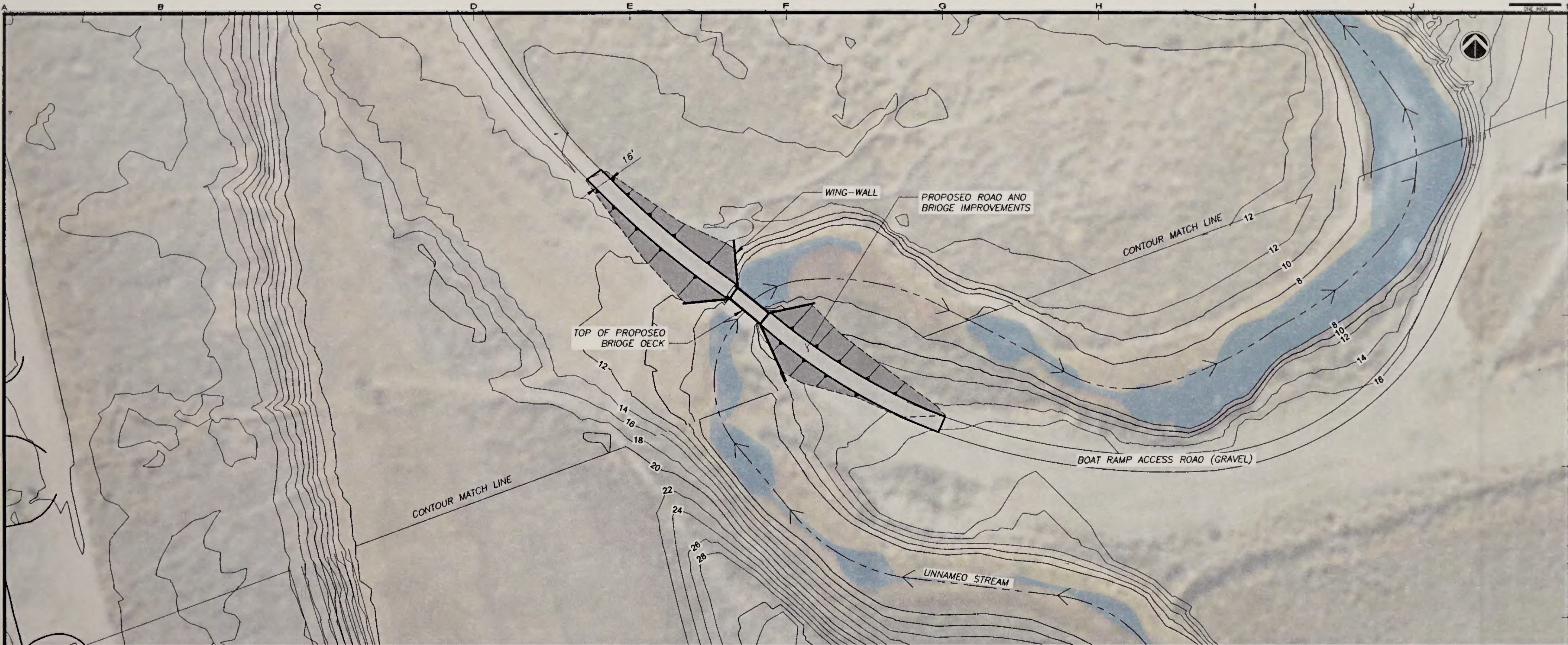
Elevate Bridge at Site 2 Above Extreme High Water - See Section 2.10.1 pg 18

| ITEM | QUANTITY | DESCRIPTION | UNIT PRICE | TOTAL PRICE |
|---|---|---|---|---|
| 1 | 1 L.S. | Mobilization/Demobilization | 2,300,000.00 | 2,300,000 |
| 2 | 92,800 C.Y. | Gravel Fill | 50.00 | 4,640,000 |
| 3 | 28,824 C.Y. | Riprap | 375.00 | 10,809,000 |
| 4 | 42,000 S.Y. | Geotextile Fabric | 5.00 | 210,000 |
| | | | | |
| | | | | |
| | | | | |

| | | |
|---|---|---|
| Subtotal Construction | | $17,959,000 |
| Land Acquisition | | 0 |
| City Administration | @ 5% | 898,000 |
| Design | @ 12% | 2,155,100 |
| Construction Management | @ 15% | 2,693,900 |
| Project Contingency | @ 15% | 2,693,900 |
| 1 Years Inflation | @ 3% | 538,800 |
| Subtotal | | $26,938,700 |

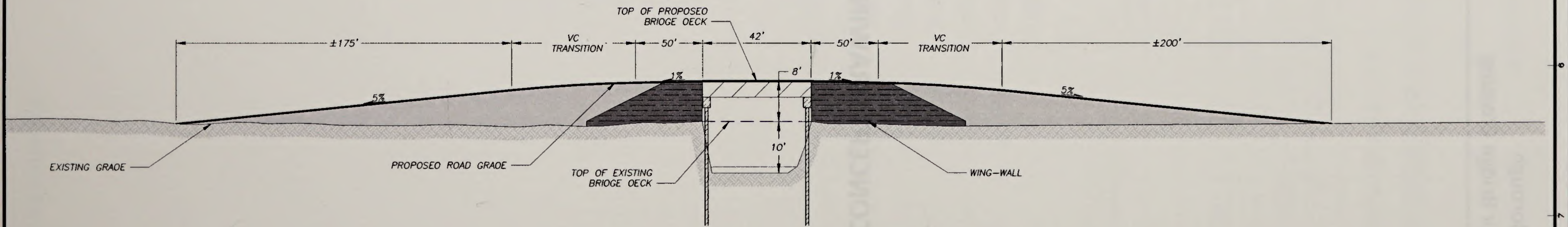
# APPENDIX B

# CONCEPT DRAWINGS FOR UPPER STREAM CROSSING (SITE 2)




SITE 2-ALTERNATIVE 2A PLAN

SCALE: 1"=50'




SITE 2-ALTERNATIVE 2A SECTION

SCALE: N.T.S

REVISIONS

| MARK | DATE | DESCRIPTION |
|---|---|---|
| 1 | | |
| 2 | | |
| 3 | | |
| 4 | | |
| 5 | | |

HDL HATTENBURG DILLEY & LINNELL
Engineering Consultants

- ENGINEERING
- SURVEYING
- PROJECT MANAGEMENT
- ENVIRONMENTAL
- EARTH SCIENCE
- PLANNING

(907) 564-2120 - ANCHORAGE
(907) 746-5230 - PALMER
WWW.HDLALASKA.COM

NOT FOR CONSTRUCTION

BRIDGE CORSSINGS

NORTH SLOPE BOROUGH

NUIQSUT, ALASKA

SHEET TITLE: SITE 2-ALTERNATIVE 2A

SHEET: 2A.1

DRAWN BY: WJB | CHECKED BY: AJB

DATE: 12-17-15 | SCALE: 1"=50'

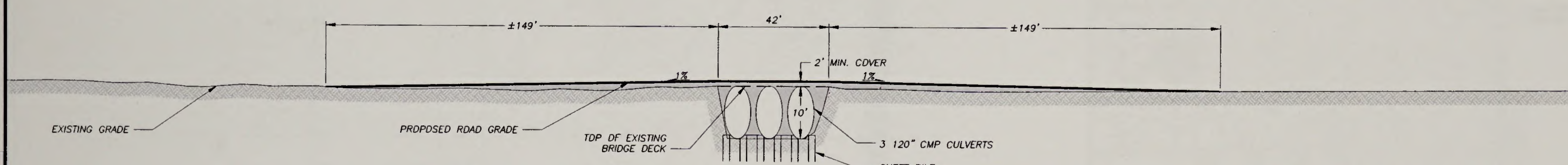
JOB NUMBER: 15-031

LAYOUT: f1.2

H:\Jobs\15-031 North Slope Borough PARs 2015 Term (NSB)\02 - NUI Bridge Crossing Repairs\CAD\DRAWINGS\BRIDGE CROSSINGS SITE 2 ALT, 1=1, 12/17/15 at 12:04 by WJB
LAYOUT: 11.2


1 / 2A.1 SITE 2-ALTERNATIVE 2B PLAN

SCALE: 1"=50'




2 / 2A.1 SITE 2-ALTERNATIVE 2B SECTION

SCALE: N.T.S

| REVISIONS MARK | DATE | DESCRIPTION |
|---|---|---|
| 1 | | |
| 2 | | |
| 3 | | |
| 4 | | |
| 5 | | |

NOT FOR CONSTRUCTION

HDL HATTENBURG DILLEY & LINNELL Engineering Consultants

- ENGINEERING
- SURVEYING
- PROJECT MANAGEMENT
- ENVIRONMENTAL
- EARTH SCIENCE
- PLANNING

(907) 564-2120 - ANCHORAGE
(907) 746-5230 - PALMER
WWW.HDLALASKA.COM

BRIDGE CORSSINGS

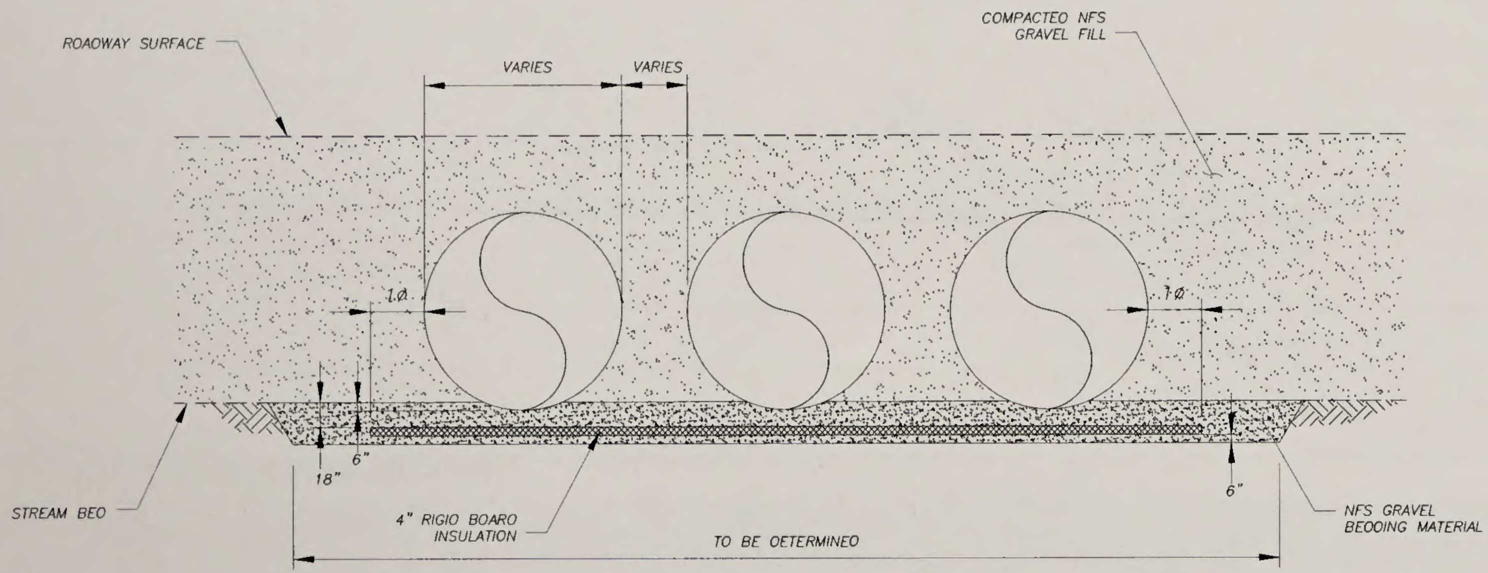
NORTH SLOPE BOROUGH

NUIQSUT, ALASKA

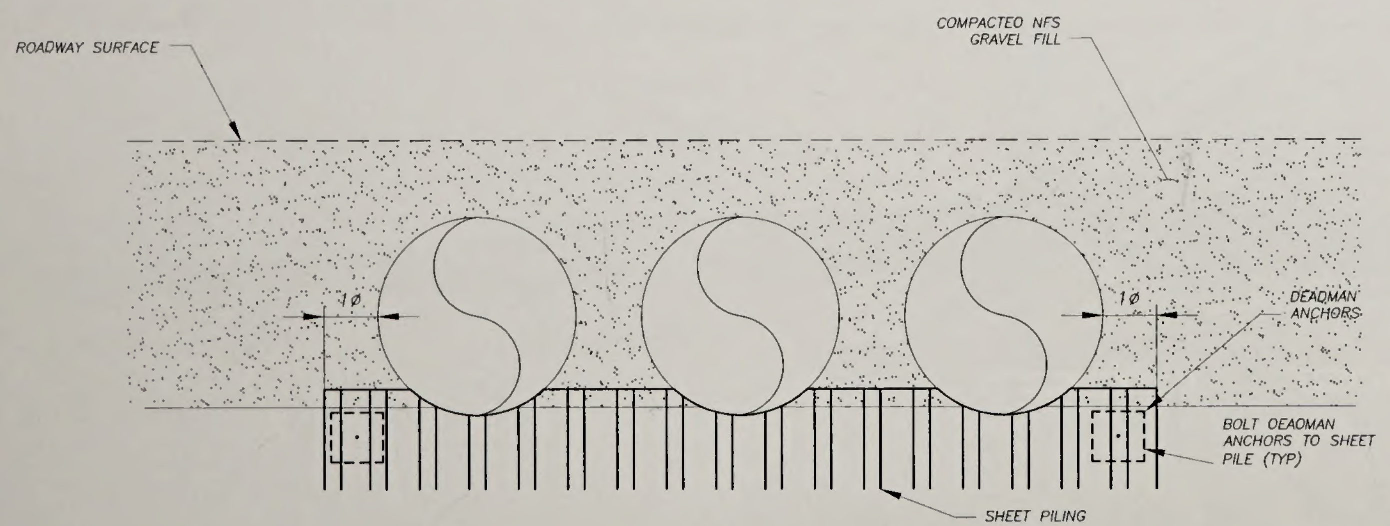
SHEET TITLE: SITE 2-ALTERNATIVE 2B

SHEET: 2B.1

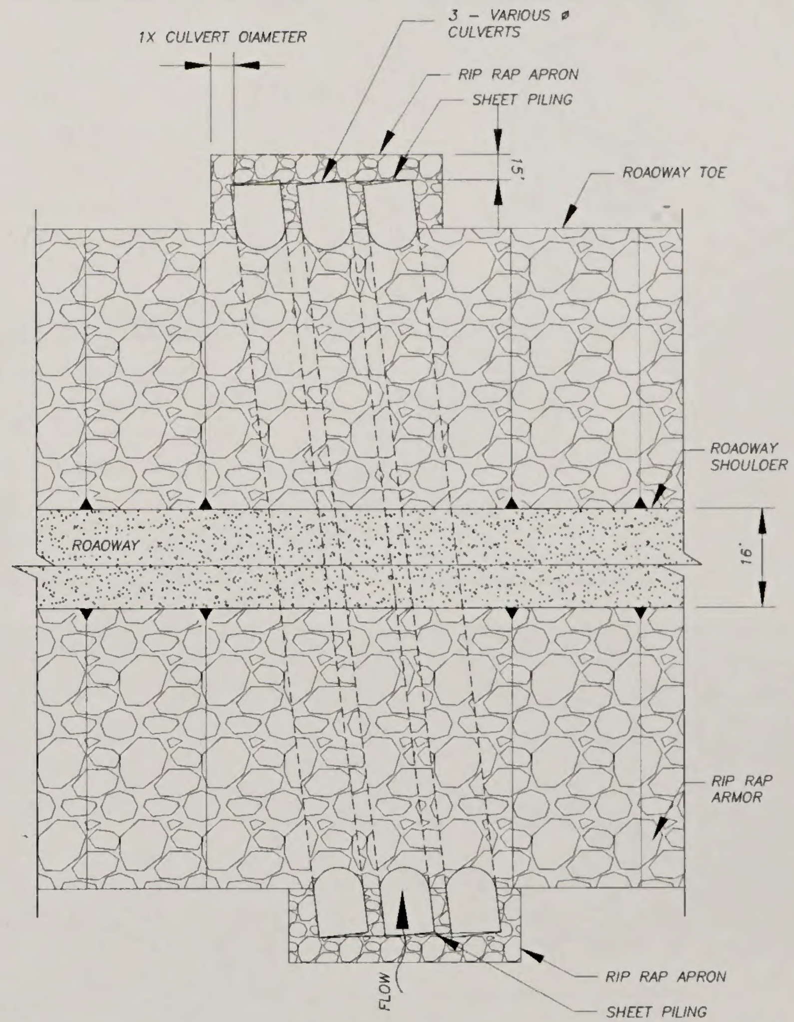
| DRAWN BY: WJB | CHECKED BY: AJB |
|---|---|
| DATE: 12-17-15 | SCALE: 1"=50' |
| JOB NUMBER: 15-031 | |




1 2B/3B.2 TYPICAL CULVERT DETAIL
SCALE: N.T.S




2 2B/3B.2 TYPICAL SHEET PILE DETAIL
SCALE: N.T.S




3 2B/3B.2 CULVERT LAYOUT PLAN
SCALE: N.T.S

REVISIONS
1
2
3
4
5

HDL HATTENBURG DILLEY & LINNELL
Engineering Consultants
· ENGINEERING
· SURVEYING
· PROJECT MANAGEMENT
· ENVIRONMENTAL
· EARTH SCIENCE
· PLANNING
(907) 564-2120 · ANCHORAGE
(907) 746-5230 · PALMER
WWW.HDLALASKA.COM

NOT FOR CONSTRUCTION

BRIDGE CORSSINGS
NORTH SLOPE BOROUGH
NUIQSUT, ALASKA

SHEET TITLE
DETAILS

SHEET
2B.2/3B.2

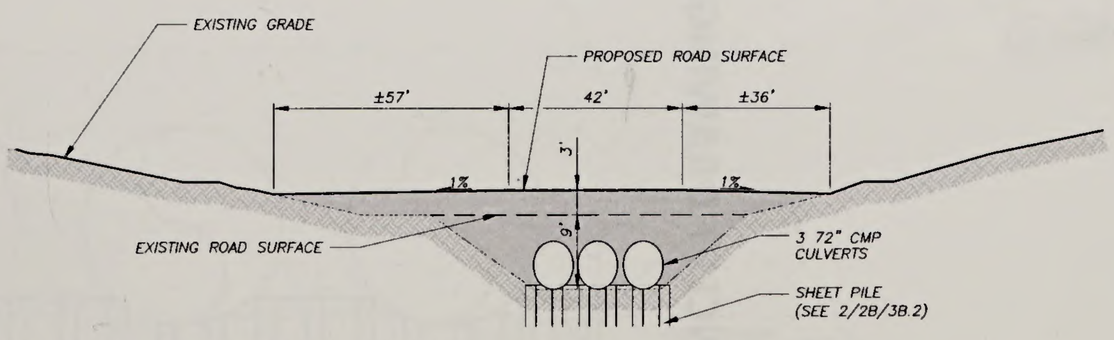
| DRAWN BY: WJB | CHECKED BY: AJB |
|---|---|
| DATE: 12-17-15 | SCALE: 1"=20' |
| JOB NUMBER: 15-031 | |

# APPENDIX C

# CONCEPT DRAWINGS FOR TRIBUTARY STREAM CROSSING (SITE 3)


## SITE 3-ALTERNATIVE 3B PLAN

1 / 3B.1 SCALE: 1"=20'




## SITE 3-ALTERNATIVE 3B SECTION

2 / 3B.1 SCALE: N.T.S

REVISIONS

NOT FOR CONSTRUCTION

HDL HATTENBURG DILLEY & LINNELL Engineering Consultants

- ENGINEERING
- SURVEYING
- PROJECT MANAGEMENT
- ENVIRONMENTAL
- EARTH SCIENCE
- PLANNING

(907) 564-2120 - ANCHORAGE
(907) 746-5230 - PALMER
WWW.HDLALASKA.COM

BRIDGE CORSSINGS

NORTH SLOPE BOROUGH

NUIQSUT, ALASKA

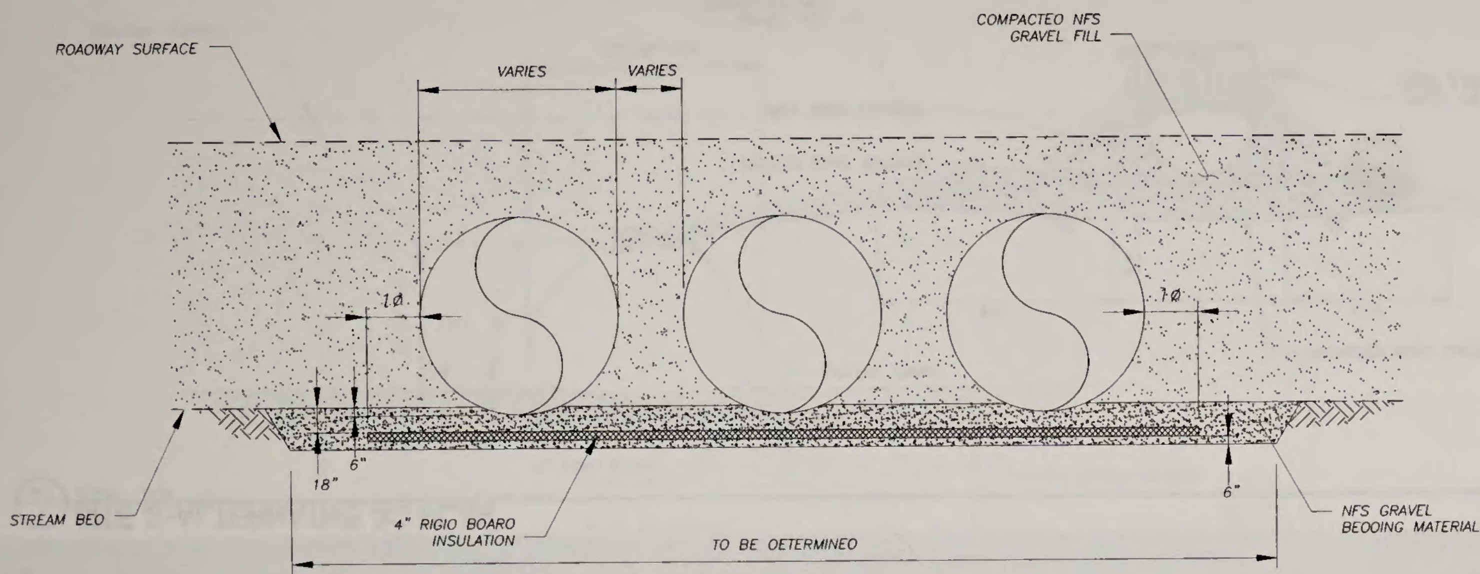
SHEET TITLE: SITE 3- ALTERNATIVE 3B

SHEET: 3B.1

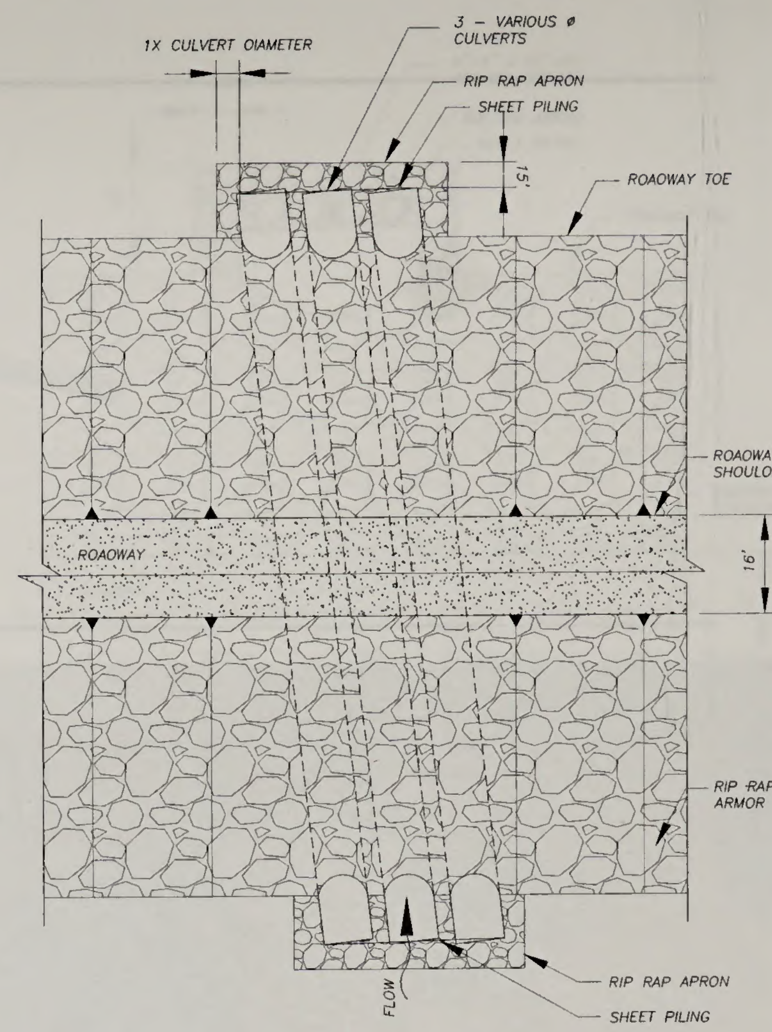
DRAWN BY: WJB | CHECKED BY: AJB

DATE: 12-17-15 | SCALE: 1"=20'

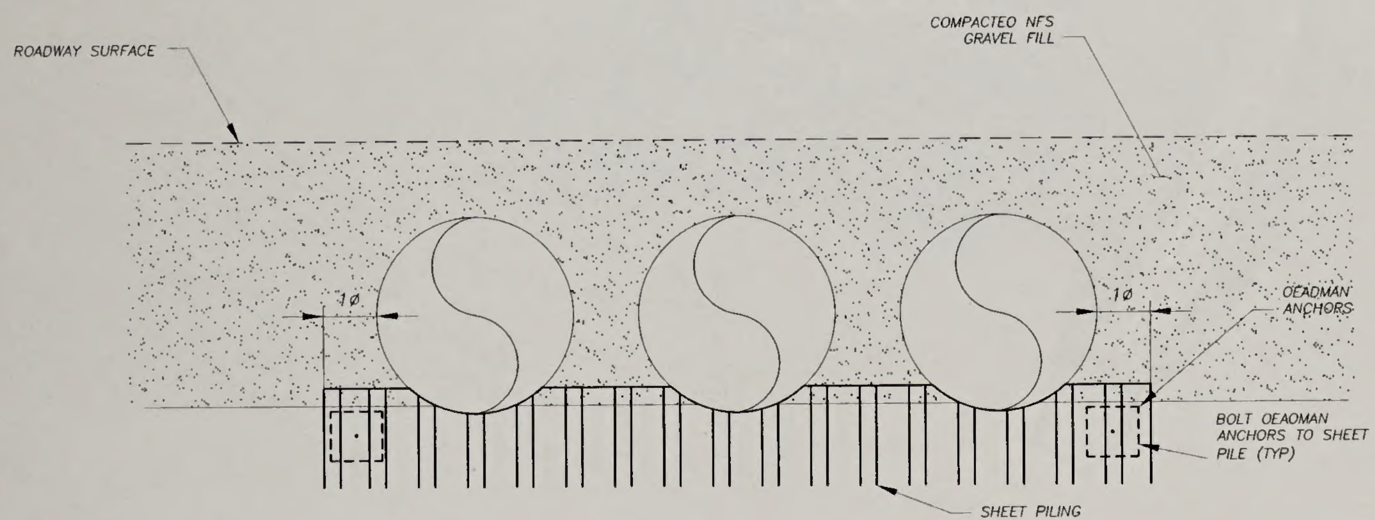
JOB NUMBER: 15-031




1 2B/3B.2 TYPICAL CULVERT DETAIL
SCALE: N.T.S




3 2B/3B.2 CULVERT LAYOUT PLAN
SCALE: N.T.S




2 2B/3B.2 TYPICAL SHEET PILE DETAIL
SCALE: N.T.S

REVISIONS
MARK | DATE | DESCRIPTION
1
2
3
4
5

HDL HATTENBURG DILLEY & LINNELL
Engineering Consultants
• ENGINEERING • SURVEYING • PROJECT MANAGEMENT
• ENVIRONMENTAL • EARTH SCIENCE • PLANNING
(907) 564-2120 · ANCHORAGE
(907) 746-5230 · PALMER
WWW.HDLALASKA.COM

NOT FOR CONSTRUCTION

BRIDGE CORSSINGS
NORTH SLOPE BOROUGH
NUIQSUT, ALASKA

SHEET TITLE
DETAILS

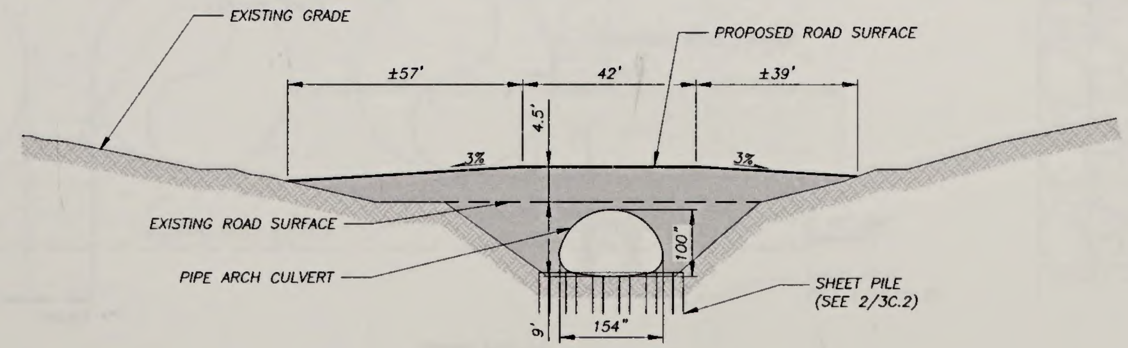
SHEET
2B.2/3B.2

| DRAWN BY: | CHECKED BY: |
|---|---|
| WJB | AJB |
| DATE: 12-17-15 | SCALE: 1"=20' |

JOB NUMBER
15-031


## SITE 3-ALTERNATIVE 3C PLAN

1 / 3C.1 SCALE: 1"=20'




## SITE 3-ALTERNATIVE 3C SECTION

2 / 3C.1 SCALE: N.T.S

HDL HATTENBURG DILLEY & LINNELL Engineering Consultants

- ENGINEERING
- SURVEYING
- PROJECT MANAGEMENT
- ENVIRONMENTAL
- EARTH SCIENCE
- PLANNING

(907) 564-2120 - ANCHORAGE
(907) 746-5230 - PALMER
WWW.HDLALASKA.COM

NOT FOR CONSTRUCTION

BRIDGE CORSSINGS

NORTH SLOPE BOROUGH

NUIQSUT, ALASKA

SITE 3- ALTERNATIVE 3C

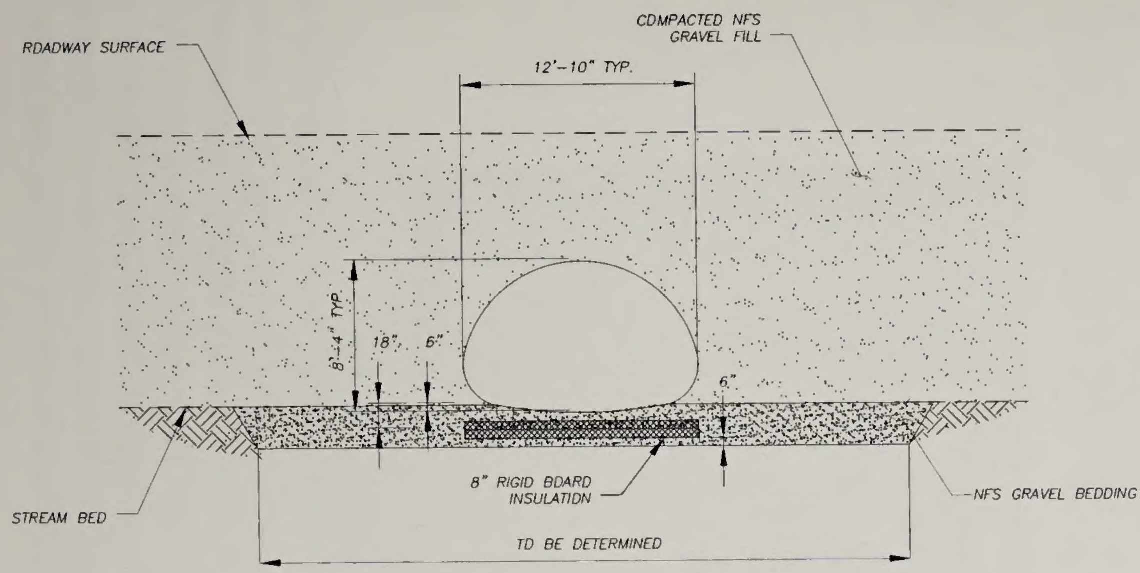
3C.1

DRAWN BY: WJB CHECKED BY: AJB

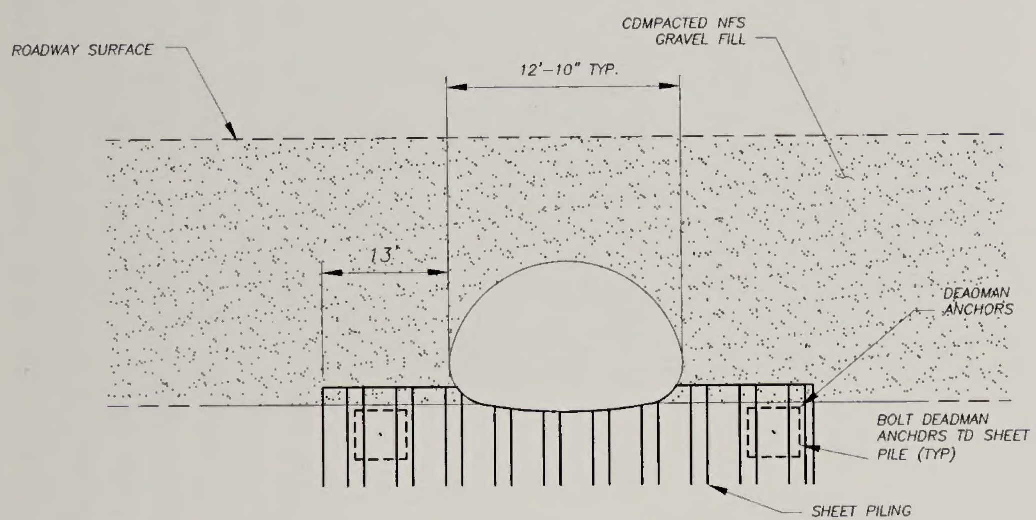
DATE: 12-17-15 SCALE: 1"=20'

JOB NUMBER: 15-031

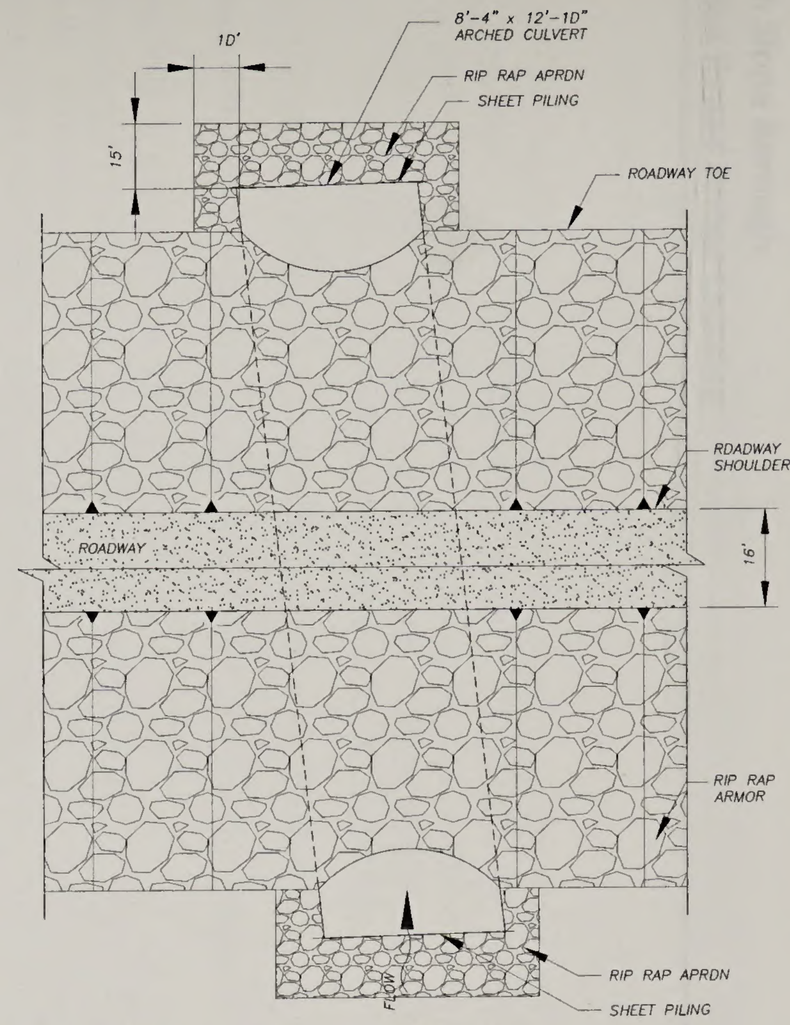
H:\Jobs\15-031 North Slope Borough PARs 2015 Term (NSB)\02 - NUI Bridge Crossing Repairs\CAD\DRAWINGS\BRIDGE CROSSINGS alternate, 1=1, 12/17/15 at 11:33 by WJB
LAYOUT: 3C.1




1 3C.2 TYPICAL PIPE ARCH CULVERT DETAIL
SCALE: N.T.S




2 3C.2 TYPICAL PIPE ARCH SHEET PILE DETAIL
SCALE: N.T.S




3 1.1 PIPE ARCH CULVERT LAYOUT PLAN
SCALE: N.T.S

REVISIONS
NOT FOR CONSTRUCTION

HDL HATTENBURG DILLEY & LINNELL
Engineering Consultants
• ENGINEERING • ENVIRONMENTAL
• SURVEYING • EARTH SCIENCE
• PROJECT MANAGEMENT • PLANNING
(907) 564-2120 - ANCHORAGE
(907) 746-5230 - PALMER
WWW.HDLALASKA.COM

BRIDGE CORSSINGS
NORTH SLOPE BOROUGH
NUIQSUT, ALASKA

SHEET TITLE: DETAILS
SHEET: 3C.2
DRAWN BY: WJB
CHECKED BY: AJB
DATE: 12-17-15
SCALE: 1"=20'
JOB NUMBER: 15-031

# APPENDIX D

# HDL SITE INSPECTION REPORT

HATTENBURG DILLEY & LINNELL
Engineering Consultants

# MEMORANDUM

**DATE:** September 8, 2015

**TO:** Jack Frantz, North Slope Borough Project Administrator

**FROM:** Adam Bruscher, Project Engineer

**RE:** August 20-21, NSB PAR Bridge Crossing Repair - Nuiqsut Site Inspection

CIVIL ENGINEERING
GEOTECHNICAL ENGINEERING
TRANSPORTATION ENGINEERING
ENVIRONMENTAL SERVICES
PLANNING
SURVEYING
CONSTRUCTION ADMINSTRATION
MATERIAL TESTING
RIGHT-OF-WAY SERVICES

On Thursday August 20, 2015, I departed Anchorage with Scott Hattenburg and Kyle Albert of Hattenburg Dilley & Linnell via Alaska Airlines at 7:35 AM and arrived in Prudhoe Bay at 9:17 AM. We departed Prudhoe Bay at 1:30 PM via Ravn Alaska and arrived in Nuiqsut at 1:50 PM. Upon arriving in Nuiqsut we were greeted by Kuukpik Hotel staff and transported to Kuukpikmiut Subsistence Oversight Panel Inc. for our vehicle rental. Upon obtaining the vehicle rental we checked into our rooms at the Kuukpik Hotel.

Temperatures were in the low-40°Fs during the day and mid-30°Fs at night. Conditions were overcast during the site visit.

The purpose for the trip was to investigate and gather the field information necessary to prepare a Project Analysis Report (PAR) for the North Slope Borough (Borough) to repair two temporary culvert crossings and one failed bridge crossing (Figure 1). During our visit to Nuiqsut we also completed an as-built survey of the PAPI pads for the Nuiqsut Airport.

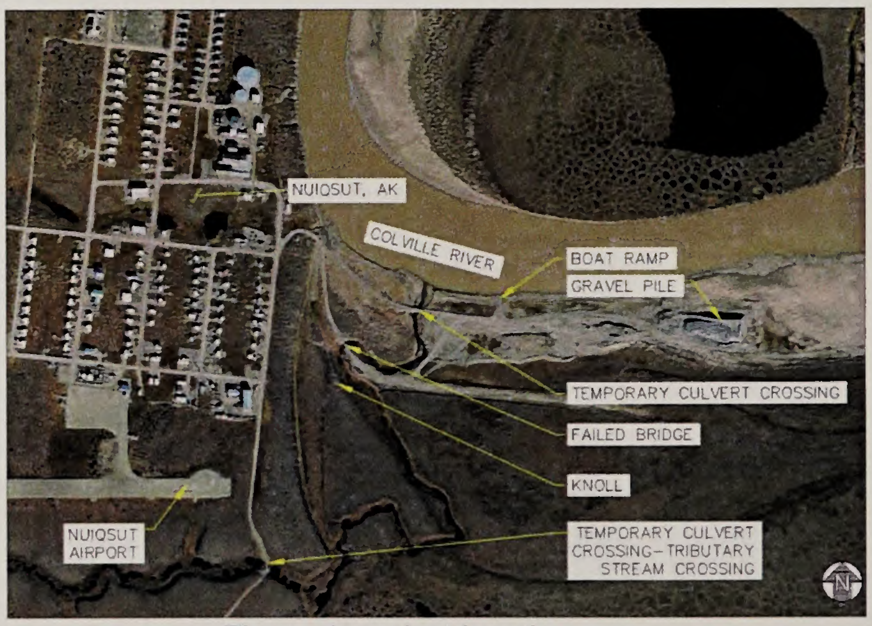


Figure 1: project location map

Upon departing the hotel we spoke with Thomas, the Public Works Supervisor for Nuiqsut. He mentioned that extreme high water events occur during the spring ice breakup and the only visible landmark is the gravel pile located 0.7 miles east of the village and a knoll 0.1 miles east of the village (Figure 1). He also informed us that the backwater from the Colville River causes the water level to rise well above the access road, thus annually washing out the lower stream crossing by the boat launch. The tributary stream crossing south of the airport is armored with sandbags and though it overtops annually, it has not washed out.

For the remainder of the day on August 20th we performed a preliminary investigation of the three stream crossings and as a separate project as-built the newly constructed PAPI pads at the airport.

On August 21st we started our field work at the temporary culvert crossing on the boat ramp access road. We gathered measurements on the existing pipes, roadway dimensions. We setup a level and took field measurements on the top of the roadway, top of pipes and water level at the culverts. We collected a cross section of the stream 100 feet upstream of the bridge, recording relative elevations at 10' intervals.

Figure 2: Temporary culvert crossing, Road to the Boat Launch, two 48-inch CMPs

Next we visited the failed bridge location. We noted the condition of the bridge, what failed, and the sizes and dimension of the structural components of the bridge. We setup a level and took relative elevation measurements on the centerline of the bridge deck, the water surface, channel bottom, and centerline of the road 75 feet East and West of the structure. To better understand the channel hydraulics we recorded a reference cross section roughly 250 feet downstream of the bridge.

Figure 3: Failed 42-foot span Bridge, Road to Boat Launch

The last structure we visited was the tributary stream crossing south of the airport on the road to the water source. We gathered data in a similar fashion to the first culvert crossing and noted the dimensions of the existing pipes and roadway widths. A level was used to determine relative heights for the top of the roadway, culverts, and water surface. A reference cross section was collected 100 feet upstream of the crossing. High water debris

lines were located at the edges of the cross-section. The road embankment at this crossing was armored with sandbags that appeared to help protect the structure from erosion.

Figure 4: Temporary culvert crossing – Road to Water Source, three 48-inch diameter CMPs

Upon completing visits to all three structures, we revisited the failed bridge location and investigated surrounding areas to locate the high water debris lines. We found two locations with evidence of debris from high water events. We estimated that the lower of the two debris lines represented a normal high water event due to the large amount of debris in the area. The relative elevation of this debris line was approximately 2 feet higher than the centerline of the bridge deck. We estimated the higher of the debris lines represented an extreme high water event. This debris line was measured to be approximately 8.5 feet higher than the bridge deck.

Figure 5: High water debris line

After documenting the location and relative elevations of the high water lines we gathered our equipment, departed from Nuiqsut at 3:50 PM and arrived in Anchorage at 8:39 PM.